DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket No. PHMSA–2013–0255]

RIN 2137–AF06

Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: PHMSA is proposing to revise the Pipeline Safety Regulations applicable to newly constructed and entirely replaced onshore natural gas transmission and hazardous liquid pipelines to mitigate ruptures. Additionally, PHMSA is revising the regulations regarding rupture detection to shorten pipeline segment isolation times. These proposals address congressional mandates, incorporate recommendations from the National Transportation Safety Board, and are necessary to reduce the consequences of large-volume, uncontrolled releases of natural gas and hazardous liquid pipeline ruptures.

DATES: Persons interested in submitting written comments on this NPRM must do so by April 6, 2020.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2013–0255 by any of the following methods:

Comments should reference Docket No. PHMSA–2013–0255 and may be submitted in the following ways:

- *Federal eRulemaking Portal: http://www.regulations.gov.* This site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the online instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* U.S. DOT Docket Operations Facility (M–30), West Building, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* DOT Docket Operations Facility, West Building, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590 between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays.

Instructions: Identify the docket number, PHMSA–2013–0255, at the beginning of your comments. If you mail your comments, submit two copies. To confirm receipt of your comments, include a self-addressed, stamped postcard.

Note: All comments are posted electronically in their original form, without changes or edits, including any personal information.

Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

Confidential Business Information

Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA) (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this notice contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 CFR 190.343, you may ask PHMSA to give confidential treatment to information you give to the agency by taking the following steps: (1) Mark each page of the original document submission containing CBI as ''Confidential''; (2) send PHMSA, along with the original document, a second copy of the original document with the CBI deleted; and (3) explain why the information you are submitting is CBI. Unless you are notified otherwise, PHMSA will treat such marked submissions as confidential under the Freedom of Information Act, and they will not be placed in the public docket of this notice. Submissions containing CBI should be sent to Robert Jagger at U.S. DOT, PHMSA, PHP–30, 1200 New Jersey Avenue SE, PHP–30, Washington, DC 20590–0001. Any commentary PHMSA receives that is not specifically designated as CBI will be placed in the public docket for this matter.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA seeks notice and comment on proposed revisions to the Pipeline Safety Regulations for both gas transmission and hazardous liquid pipelines. PHMSA is proposing regulations to meet a congressional mandate calling for the installation of remote-control valves (RCV), automatic shutoff valves (ASV), or equivalent technology, on all newly constructed and fully replaced gas transmission and hazardous liquid lines. However, consistent with the mandate, PHMSA recognizes that there may be locations where it is not economically, technically, or operationally feasible to install RCVs, ASVs, or equivalent technology. Therefore, PHMSA is proposing to allow operators to install manual valves at these locations, provided operators have a sufficient justification for using a manual valve instead of an RCV, an ASV, or equivalent technology, and provided that operators appropriately station personnel to ensure that a manual valve can be closed within the same 40-minute timeframe PHMSA is proposing in this rulemaking for RCVs, ASVs, and equivalent technology. This will help to ensure that a consistent level of safety is provided whether operators use manual valves, RCVs, ASVs, or equivalent technology.

This rulemaking (NPRM) is proposing to apply this installation requirement to those newly constructed or fully replaced pipelines that are greater-than-or-equal-to 6 inches in nominal diameter. PHMSA is also proposing regulations to improve pipeline operators' responses to large-volume, uncontrolled release events that may occur during the operation of certain onshore gas transmission, hazardous liquid, and carbon dioxide pipelines of particular diameters and in specific locations.[1] This NPRM would define a ''rupture'' event through certain metrics or observations, require operators of applicable lines to meet new regulatory standards to identify ruptures more quickly, respond to them more effectively, and mitigate their impacts. PHMSA's existing regulations require that operators take several steps to reduce the risk of potential leaks and failures, including testing and assessments, continuous monitoring of operations, and physical surveys and patrols of their pipelines' right-of-ways. Based on congressional direction, National Transportation Safety Board (NTSB) safety recommendations from accident investigations, recommendations from the Government Accountability Office (GAO), and PHMSA's analysis of incidents and evolving technology, this rule proposes to define large-volume, uncontrolled releases of both natural gas and hazardous liquids as pipeline ''ruptures'' and proposes standards to mitigate those ruptures.

One such rupture occurred on July 25, 2010, in Marshall, Michigan, resulting in the spill of approximately 800,000 gallons of crude oil into the Kalamazoo River and approximately $1 billion in damages. The operator took 18 hours to confirm the pipeline rupture. Following confirmation of the rupture, the failed segment of the pipeline was immediately isolated using remote-controlled valves.

Another incident occurred on September 9, 2010, in San Bruno, California, when a gas pipeline ruptured, causing a fire. This incident involved the uncontrolled release of natural gas for 95 minutes, severely hampering firefighting efforts, before the operator closed the mainline valves. The incident resulted in 8 deaths, 51 injuries requiring hospitalization, the destruction of 38 homes, damage to 70 other homes, and the evacuation of approximately 300 houses.

These two incidents are examples of release events where consequences can be significantly aggravated by some combination of missed opportunities by operators, including: (1) Identifying that a rupture has occurred; (2) failing to take appropriate and prompt action(s) once a rupture has been identified, including calling 911 following the rupture, activating emergency response protocols, and notifying first responders and public officials; and (3) failing to promptly access and close available segment isolation valves that would be most beneficial for mitigating the impact of the rupture.

Following those incidents, Congress issued the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act), which contained several mandates to improve pipeline safety. Section 4 of the 2011 Pipeline Safety Act requires PHMSA to issue regulations, if appropriate, requiring the use of automatic or remote-controlled shut-off valves, or equivalent technology, on newly constructed or replaced natural gas or hazardous liquid pipeline facilities.

PHMSA is proposing these regulations to improve operational practices related to rupture mitigation and to shorten rupture-segment isolation times by requiring operators of applicable lines to identify a rupture quickly, implement response procedures, and fully close pipeline mainline valves to terminate the uncontrolled release of commodity as soon as practicable. PHMSA is also requiring operators to install automatic shutoff, remote-controlled, or equivalent valves on newly constructed and entirely replaced pipelines to meet the section 4 mandate. PHMSA seeks comment from the public on these proposals.

Enbridge, the pipeline operator responsible for the incident near Marshall, MI, had remote-control technology installed on the ruptured pipeline. However, a failure to identify the rupture within a short amount of time rendered the technology essentially useless. Therefore, PHMSA believes a regulation requiring the installation of rupture-mitigating valves should be paired with a standard delineating when an operator must identify a rupture and actuate those valves. PHMSA also believes that this standard will be most cost-effective when applied to onshore hazardous liquid and natural gas transmission pipelines of certain diameters in high-consequence areas (HCA), areas that could affect HCAs (for hazardous liquid pipelines), and Class 3 and 4 locations (for natural gas transmission pipelines),[2] where a release could have the most significant adverse consequences on public safety or the environment.

In developing these proposed regulations, PHMSA considered other mandates in the 2011 Pipeline Safety Act, as well as NTSB safety recommendations that followed the San Bruno incident;[3] GAO recommendations on the ability of operators to respond to commodity releases in HCAs;[4] technical reports commissioned by PHMSA on valves and leak detection from Oak Ridge National Laboratory (ORNL) and Kiefner and Associates, respectively;[5][6] comments received on related topics through advance notices of proposed rulemaking (ANPRM); and information gathered at public meetings and workshops.

PHMSA believes this approach, as detailed in this NPRM, will help reduce the consequences of ruptures through

[1] For brevity, reference to ''hazardous liquid pipelines'' through the remainder of this NPRM will include carbon dioxide pipelines as well, unless otherwise stipulated.

[2] A gas pipeline's class location broadly indicates the level of potential consequences for a pipeline release based upon population density along the pipeline. Class locations are determined as specified at § 192.5(a) by using a ''sliding mile'' that extends 220 yards on both sides of the centerline of a pipeline. The number of buildings within this sliding mile at any point during the mile's movement determines the class location for the entire mile of pipeline contained within the sliding mile. Class 1 locations contain 10 or fewer buildings intended for human occupancy, Class 2 locations contain 11 to 45 buildings, Class 3 locations contain 46 or more buildings, and Class 4 locations have a prevalence of 4-or-more-story buildings.

[3] ''Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, CA; September 9, 2010; NTSB Accident Report PAR–11/01; Adopted August 30, 2011. *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.*

[4] ''Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response,'' Government Accountability Office Report to Congressional Committees, January 2013. *https://www.gao.gov/assets/660/651408.pdf.*

[5] ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves and Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety;'' Oak Ridge National Laboratory; ORNL/TM–2012/411; October 31, 2012. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16701/finalvalvestudy.pdf.*

[6] ''Leak Detection Study—DTPH56–11–D–000001;'' Kiefner and Associates, Inc.; Final Report No. 12–173; December 10, 2012. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16691/leak-detection-study.pdf.*

improving both rupture identification and rupture mitigation, including more rapid and effective isolation of failed pipeline segments.

B. Summary of the Major Provisions of the Proposed Regulatory Action

This NPRM will require the installation of automatic shutoff valves, remote-control valves, or equivalent technology, on all newly constructed or entirely replaced natural gas transmission and hazardous liquid pipelines that have nominal diameters of 6 inches or greater.[7] For the purposes of this NPRM, PHMSA considers pipelines to be ''entirely replaced'' when 2 or more contiguous miles are being replaced with new pipe. PHMSA requests comments on this definition of ''entirely replaced'' in the context of the Section 4 valve installation mandate and whether it is reasonable or should be modified in the future. Additionally, for gas transmission pipelines, when a pipeline's class location changes and results in pipe replacement to meet the maximum allowable operating pressure (MAOP) requirements of the new class location, an operator would be required to install or otherwise modify valves as necessary to comply with valve spacing requirements and the proposed rupture identification and mitigation requirements.

The NPRM also would establish Federal minimum standards for the identification of ruptures and the initiation of pipeline shutdowns, segment isolation, and other mitigative actions, which are designed to reduce the volume of commodity released due to a pipeline rupture and thereby minimize potential adverse safety and environmental consequences. This NPRM also would establish standards for improving the effectiveness of emergency response. Specifically, the proposed rupture identification and mitigation regulations include: (1) Defining the term ''rupture'' as an event that results in an uncontrolled release of a large volume of commodity that can be determined according to specific criteria or that has been observed and reported to the operator; (2) a requirement to establish procedures for responding to a rupture; (3) a requirement to declare a rupture as soon as practicable but no longer than 10 minutes after initial notification or indication; (4) a requirement to immediately and directly notify the appropriate public safety answering point (9–1–1 emergency call centers) for the jurisdiction in which the rupture is located; and (5) a requirement to respond to a rupture as soon as practicable by closing rupture-mitigation valves, with complete valve shut-off and segment isolation within 40 minutes after rupture identification.

The term ''rupture-mitigation valve,'' as it pertains to this proposal, means the specific valve(s) that the operator would use to isolate a pipeline segment that experiences a rupture—the applicable ''shut-off segment'' as those are specified in this rulemaking. These valves can be any combination of automatic shutoff valves (ASVs), remote-control valves (RCVs), or equivalent technology. A ''shut-off segment,'' for the purposes of this NPRM, is the segment of applicable pipe between the rupture-mitigation valves closest to the upstream and downstream endpoints of a high-consequence area, a Class 3 location, or a Class 4 location so that the entirety of these areas is between rupture-mitigation valves. Multiple high-consequence areas, Class 3 locations, or Class 4 locations can be contained in a single shut-off segment, and all valves installed on a shut-off segment are rupture-mitigation valves. Additionally, operators would be required to perform post-accident reviews of any ruptures or other release events involving the closure of rupture-mitigation valves to ensure these proposed performance objectives are met and to apply any lessons learned system-wide. The new rupture mitigation requirements in this NPRM would take effect 12 months after the final rule is published.

In this NPRM, PHMSA is only allowing operators to install or use manual valves if they can demonstrate to PHMSA that it would be economically, technically, or operationally infeasible to install or use an ASV, RCV, or equivalent technology. Examples of where an ASV, RCV, or equivalent technology might be infeasible include locations that may have issues with communication signals, power sources, space for actuators, or physical security.

PHMSA is not proposing additional valve requirements for smaller diameter pipelines or leaks that don't meet the proposed definition of rupture in this rulemaking. PHMSA is also not requiring leak detection equipment on gas transmission and distribution pipelines as specifically recommended by NTSB Recommendation P–11–10. Pursuant to the findings in the Kiefner Leak Detection study that is referenced later in this rulemaking, it is typically more challenging to detect smaller leaks in an operationally, technically, and economically feasible manner. However, this proposed rule, for both hazardous liquid and gas transmission pipelines, requires the installation of pressure monitoring equipment at all rupture mitigation valves on both the upstream and downstream locations of the valve, which will help operators better detect ruptures and which can be used for leak detection.

PHMSA continues to address the effectiveness of leak detection systems for other non-rupture type leaks through its rulemaking on the safety of hazardous liquid pipelines;[8] research and development projects, including work on external-based leak detection sensors and acoustic pipeline leak detection systems;[9] and engagement in new or updated standards being developed by standard developing organizations, including API recommended practices 1130 and 1175.[10] The requirements in this NPRM of adding pressure detection and communication equipment at rupture mitigation valves are expected to drive further development and installation of leak detection technology and may help drive operators to make decisions to improve the capabilities of their leak detection systems to detect non-rupture-type events.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of the NPRM, as well as reasonable alternatives. Per the Preliminary Regulatory Impact Analysis (PRIA), PHMSA estimates the annual costs of the rule to be approximately $3.1 million, calculated using a 7 percent discount rate. The costs reflect the installation of valves on newly constructed and entirely replaced gas transmission and hazardous liquid pipelines, as well as incremental programmatic changes that operators will need to make to incorporate the proposed rupture detection and response procedures. PHMSA elected not to quantify the benefits of this rulemaking and instead discusses them qualitatively in the PRIA.

PHMSA is posting the PRIA for this proposed rule in the public docket. In the PRIA, costs are aggregated by compliance method to estimate total

[7] ''Nominal'' pipe size is the standard size used to refer to pipe in non-specific terms and identifies the approximate inner diameter of the pipe with a non-dimensional number.

[8] *https://www.regulations.gov/docket?D=PHMSA-2010-0229.*

[9] Details on all of PHMSA's leak detection research and development projects can be found at: *https://primis.phmsa.dot.gov/matrix/PrjQuery.rdm?text1=leak&btn=Modern+Search.*

[10] Computational Pipeline Monitoring for Liquids and Pipeline Leak Detection Program Management, respectively.

costs, by year, for the baseline and NPRM. The incremental effect of this rulemaking is estimated by taking the difference in total costs relative to the baseline. Costs are then aggregated across all years in the analysis period and annualized.

II. Background

A. General Authority

Congress has authorized Federal regulation of the transportation of gas and hazardous liquids by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*), a series of statutes that are administered by PHMSA. Congress established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481) and the safety of hazardous liquid pipelines in the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96–129). These laws give PHMSA the authority and responsibility to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas and hazardous liquids by pipeline. PHMSA prescribes and enforces comprehensive minimum safety standards for the transportation of gas and hazardous liquids by pipeline in 49 Code of Federal Regulations (CFR) parts 190–199. Among those standards, PHMSA has codified safety standards for the design, construction, testing, operation, and maintenance of gas and hazardous liquid pipelines in 49 CFR part 192, Transportation of Natural and Other Gas by Pipeline, and 49 CFR part 195, Transportation of Hazardous Liquids by Pipeline.

Part 192 prescribes minimum safety requirements for the transportation of gas by pipeline, including ancillary facilities and within the limits of the outer continental shelf as defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). Part 195 prescribes minimum safety requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide, including pipelines on the Outer Continental Shelf.

B. Major Pipeline Accidents

Although transmission pipelines are generally considered to be a very safe means of transporting natural gas and hazardous liquids,[11] they can experience large-volume, uncontrolled releases that can have severe consequences. For example, and according to PHMSA hazardous liquid pipeline accident reports from 2006 to 2016, there were 91 reported incidents on pipelines within HCAs that would have been reported as ''ruptures'' per this proposed rulemaking and would have triggered this NPRM's rupture-mitigation response provisions. Such accidents can be aggravated by some combination of: Missed opportunities by the operator to identify that a rupture has occurred; failure of operating personnel to take appropriate action(s) once a rupture is identified; delays in accessing and closing available segment isolation valves; and an inability to quickly close isolation valves that would have the most significant impact in mitigating the consequences of a rupture. Typically, these types of incidents (*i.e.,* failure events that result in rapidly occurring, large-volume releases) have been the most serious in terms of monetary and environmental damages and safety consequences—the aforementioned 91 hazardous liquid ''ruptures'' resulted in $1.21 billion dollars in damage and 88,506 bbls spilled. The Marshall, MI, and San Bruno, CA, accidents are examples of failure events that resulted in rapidly occurring, large-volume releases on high-pressure, large-diameter pipelines.

The intent of this NPRM is to improve operational practices that in turn will improve rupture mitigation and shorten rupture isolation times for certain onshore gas transmission and hazardous liquid pipelines. ''Rupture isolation time,'' as it is discussed in this NPRM, is the time it takes an operator to identify a rupture, implement response procedures, and fully close the appropriate mainline valves to terminate the uncontrolled flow of commodity from the ruptured pipeline segment.

In accident investigations, PHMSA and the NTSB have identified issues relating to the timeliness of rupture identification and the appropriateness and timeliness of operators' responses to ruptures. Typically, no single aspect contributes to the deficiencies in rupture identification and response. Instead, there were multiple contributing factors associated with the technology, equipment, procedures, and human elements that resulted in inadequate rupture identification and response efforts. In some incidents, certain aspects of an operator's rupture identification or response efforts appeared adequate, but other issues, such as delayed access to isolation valves, resulted in an inadequate response overall. For instance, in the incident near Marshall, MI, the pipeline operator had in place leak detection systems (LDS) and supervisory control and data acquisition (SCADA) systems that notified the controller of a potential rupture within minutes of the actual event, but issues related to the operator's procedures, training, and personnel response resulted in an excessive amount of time—18 hours—before the operator confirmed the rupture and initiated mitigative actions. In the incident in San Bruno, CA, the operator effectively identified there was a leak through LDS or SCADA systems but took 95 minutes to isolate the gas pipeline rupture, which caused the fire to continue to burn unabated. The NTSB noted that the operator, Pacific Gas & Electric (PG&E), lacked a detailed and comprehensive procedure for responding to large-scale emergencies such as a transmission pipeline break, and that the use of ASVs or RCVs would have reduced the amount of time taken to stop the flow of gas.

Prior to these incidents, the NTSB noted similar issues related to rupture response in its report on an incident occurring on March 23, 1994, in Edison Township, New Jersey.[12] In the Edison incident, the operator took nearly 2½ hours to stop the flow of gas. The fire that followed the rupture destroyed 8 buildings, caused the evacuation of approximately 1,500 apartment residents, and caused more than $25 million worth of property damage. The director of the operator's Gas Control division stated in the NTSB accident report that the operator could typically notify employees to close valves within 5 to 10 minutes after identifying a rupture and that the time it took to close a valve depended on the employee's travel time to the valve site. In his experience, he found that employees could usually arrive at a valve site within 15 to 20 minutes, but in some instances it took more than 1 hour for employees to arrive at certain valves after being dispatched. In its accident report, the NTSB concluded that the lack of automatic- or remote-operated valves on the ruptured line prevented the company from promptly stopping the flow of gas to the failed pipeline segment, which exacerbated damage to nearby property. Subsequently, the NTSB recommended to PHMSA's predecessor, the Research and Special Programs Administration (RSPA), that it expedite establishing requirements for installing automatic- or remote-operated mainline valves on high-pressure

[11] Energy products being shipped through the nation's 2.7 million miles of pipelines reach their destinations without incident 99.997 percent of the time. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/69671/aopl-api-speech.pdf.*

[12] National Transportation Safety Board Pipeline Accident Report; Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire; Edison, New Jersey; March 23, 1994. *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR9501.pdf.*

pipelines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline systems (P–95–1).

As recognized by Congress and several other stakeholders, these high-consequence rupture events deserve special consideration and regulatory treatment. Accordingly, PHMSA is proposing a combination of standards that focus on achieving the congressional objective of more timely rupture detection and mitigation in important areas while also requiring a broader installation of rupture-mitigating valves on newly constructed and entirely replaced pipeline infrastructure.

C. National Transportation Safety Board Recommendations

On August 30, 2011, the NTSB issued its report on the gas transmission pipeline accident that occurred in San Bruno, CA, on September 9, 2010.[13] In its report, the NTSB issued safety recommendations P–11–8 through P–11–20 to PHMSA; safety recommendations P–11–24 through P–11–31 to PG&E, the operator of the failed line; and several recommendations to other entities, including the Governor of the State of California, the California Public Utilities Commission (CPUC), the American Gas Association (AGA), and the Interstate Natural Gas Association of America (INGAA). NTSB safety recommendations P–11–9, P–11–10, and P–11–11 recommended that PHMSA require operators to immediately and directly notify the appropriate public safety answering point (9–1–1 emergency call centers) in the communities and jurisdictions where a pipeline rupture is indicated; equip their SCADA systems with tools, including leak detection systems and appropriately spaced flow and pressure transmitters along covered transmission lines, to identify leaks (and ruptures); and require automatic shut-off valves (ASV) or remote-control valves (RCV) be installed in HCAs and Class 3 and 4 locations with the valves spaced considering risk analysis factors, respectively.[14]

PHMSA determined that, although the NTSB directed these recommendations to onshore gas transmission pipelines in response to a natural gas transmission accident, certain aspects of these recommendations are also applicable to hazardous liquid pipelines, particularly as they relate to ruptures.

D. Advance Notices of Proposed Rulemaking

PHMSA published two ANPRMs seeking comments regarding the revision of several topic areas in the Pipeline Safety Regulations that are applicable to the safety of hazardous liquid pipelines (October 18, 2010; 75 FR 63774) and gas transmission pipelines (August 25, 2011; 76 FR 53086).[15] This NPRM addresses issues that were raised in the ANPRMs related to rupture detection and mitigation, including leak detection, valve spacing, valve installation, and method of valve actuation.

In response to the questions in the ANPRMs, a variety of parties representing interests from the natural gas and hazardous liquid industries, citizen groups, regulators, and local governments, provided comments. PHMSA considered these comments as discussed in Section III of this NPRM. Separately, PHMSA is addressing several other topics considered in the hazardous liquid and gas transmission ANPRMs, specifically in NPRMs titled ''Safety of Hazardous Liquid Pipelines'' (October 13, 2015; 80 FR 61610) and ''Safety of Gas Transmission and Gathering Pipelines'' (April 8, 2016; 81 FR 20722).

E. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and Related Studies

Public Law 112–9, known as the ''Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011'' (2011 Pipeline Safety Act), was enacted on January 3, 2012. Several of the 2011 Pipeline Safety Act's statutory requirements relate directly to the topics addressed in the ANPRMs, which have an impact on this proposed rulemaking. This NPRM is, in part, a response to the mandates of section 4 and section 8 of the 2011 Pipeline Safety Act.

i. Section 4—Automatic and Remote-Controlled Shut-Off Valves

Section 4 of the 2011 Pipeline Safety Act directs the Secretary of Transportation (Secretary), if appropriate, to require by regulation the use of ASVs or RCVs, or equivalent technology, where it is economically, technically, and operationally feasible, on hazardous liquid and natural gas transmission pipeline facilities that are constructed or entirely replaced after the date on which the Secretary issues the final rule containing such requirements. PHMSA is proposing to address this mandate by establishing the minimum standards described in this NPRM. These standards were also developed in consideration of NTSB Recommendations P–11–10 and P–11–11, the GAO Report GAO–13–168, ''Better Data and Guidance Needed to Improve Pipeline Operator Incident Response,'' [16] and ORNL Report/TM–2012/411, ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines With Respect to Public and Environmental Safety,'' which was performed in response to the 2011 Pipeline Safety Act.[17]

a. GAO Report GAO–13–168

Section 4 of the 2011 Pipeline Safety Act also required the development of a study by the Comptroller General on the ability of pipeline operators to respond to a hazardous liquid or gas release from a pipeline segment located in an HCA. This study was published by the GAO in January 2013 and recommended PHMSA take the following two actions:

1. Improve the reliability of incident response data to improve operators' incident response times, and use this data to evaluate whether to implement a performance-based framework for incident response times, and

2. Assist operators in determining whether to install automated valves by using PHMSA's existing information sharing mechanisms to alert all pipeline operators of inspection and enforcement guidance that provides additional information on how to interpret regulations on automated valves, and share approaches used by operators for making decisions on whether to install automated valves.

The GAO report noted that defined performance-based goals, established with reliable data and sound agency assessments, could result in improved operator response to incidents, with ASV and RCV installation and use being one of the determining factors. The GAO further noted that, although the current PHMSA regulations for incident response and the installation and use of ASVs and RCVs are performance-based, they are very general, currently requiring operators to respond to incidents in a ''prompt and effective

[13] NTSB/PAR–11/01, PB2011–916501, *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire.*

[14] NTSB Safety Recommendation addressed to PHMSA; September 26, 2011; *https://www.ntsb.gov/safety/safety-recs/recletters/P-11-008-020.pdf.*

[15] See *www.regulations.gov,* dockets PHMSA–2010–0229 and PHMSA–2011–0023, respectively, for both the ANPRMs and NPRMs.

[16] Published January 2013; *www.regulations.gov* (Docket ID PHMSA–2013–0255–0002).

[17] Published October 31, 2012; *www.regulations.gov* (Docket ID PHMSA–2013–0255–0004).

manner,'' [18] and requiring operators to install ASVs, RCVs, or emergency flow restricting devices (EFRD) if an operator determines, through risk analysis, such valves are necessary to protect HCAs.[19]

More clearly defined goals can help operators identify actions that could improve their ability to respond to certain types of incidents consistently and promptly, though identical incident response actions are not appropriate for all circumstances due to pipelines having variable locations, equipment needs, configurations, and operating conditions. PHMSA agrees with the GAO's conclusions that a more specific standard, in conjunction with carefully selected requirements, could be more effective in improving incident response times, particularly when ruptures are involved.

The GAO report also concluded that the primary advantage of installing and using automated valves is that operators can respond more quickly to isolate the affected pipeline segment and reduce the amount of commodity released. Although the report suggested that using automated valves can have certain disadvantages, including the potential for accidental closures, which makes it appropriate for operators to decide whether to install automated valves on a case-by-case basis, the report recognized that a faster incident response time could reduce the amount of property damage from secondary fires (after an initial pipeline rupture) by allowing fire departments to extinguish the fires sooner. In addition, for hazardous liquid pipelines, a faster incident response time could result in lower costs for environmental remediation efforts and less commodity loss.

PHMSA applied these principles and the GAO's findings and recommendations in developing the standards proposed in this NPRM. The proposed amendments in this NPRM would also include new, specific, post-accident review requirements in §§ 192.617(a) and 195.402(c)(5)(i) and (ii). Operators would make those post-accident reviews available for PHMSA to inspect, and PHMSA could use those reviews in disseminating lessons learned to other operators and to better inform future rulemakings. The GAO report may be reviewed at *http://www.regulations.gov* by searching for Docket No. PHMSA–2013–0023.

b. ORNL Report ORNL/TM–2012/411

In March 2012, PHMSA requested assistance from ORNL to perform a study to address the issues outlined in Section 4 of the 2011 Pipeline Safety Act and those raised by the NTSB in its accident report for the September 9, 2010, San Bruno natural gas pipeline incident. The ORNL study assessed the effectiveness of valve-closure swiftness in mitigating the consequences of natural gas and hazardous liquid pipeline releases on public and environmental safety. It also evaluated the technical, operational, and economic feasibility and potential benefits of installing ASVs and RCVs in newly constructed and fully replaced pipelines. The study concluded that:

1. In general, installing ASVs and RCVs on newly constructed and fully replaced natural gas transmission and hazardous liquid pipelines is technically feasible, provided sufficient space is available for the valve body, actuators, power source, sensors and related electronic equipment, and personnel required to install and maintain the valve; and is operationally feasible, provided the communication links between the RCV site and the control room are continuous and reliable.

2. There is evidence that it is economically feasible to install ASVs and RCVs on newly constructed and fully replaced natural gas transmission and hazardous liquid pipelines and the benefits would exceed the costs for the release scenarios considered in the study. However, it is necessary to consider site-specific variables in determining whether installing ASVs or RCVs on newly constructed or fully replaced pipelines is economically feasible in a particular situation.

3. Installing ASVs and RCVs on newly constructed and fully replaced natural gas and hazardous liquid pipelines can be an effective strategy for mitigating potential fire consequences resulting from a release and subsequent ignition. Adding automatic closure capability to valves on newly constructed or fully replaced hazardous liquid pipelines can also be an effective strategy for mitigating potential socioeconomic and environmental damage resulting from a release that does not ignite.

4. For hazardous liquid pipelines, installing ASVs and RCVs can be an effective strategy for mitigating potential fire damage resulting from a pipe opening-type breaks [20] and subsequent ignition, provided the leak is detected and the appropriate ASVs and RCVs close completely so that the damaged pipeline segment is isolated within 15 minutes after the break.

PHMSA used the conclusions of the ORNL Report in developing this NPRM and as a basis for proposing to implement standards for valve installation per Section 4 of the 2011 Pipeline Safety Act. The report may be reviewed at *http://www.regulations.gov* by searching for Docket No. PHMSA–2013–0255–0004.

ii. Section 8—Leak Detection

Section 8 of the 2011 Pipeline Safety Act required the Secretary to submit to Congress a report on leak detection systems (LDS) utilized by operators of hazardous liquid pipeline facilities, including transportation-related flow lines, and to establish technically, operationally, and economically feasible standards for the capability of leak detection systems to detect leaks.

PHMSA responded to the 2011 Pipeline Safety Act's Section 8 mandate by contracting with Kiefner and Associates, Inc. to prepare a leak detection study. The Kiefner study examined LDS used by operators of hazardous liquid and natural gas transmission pipelines and included an analysis of the technical limitations of current LDS, the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies. It also reviewed the practicality of establishing technically, operationally, and economically feasible standards for LDS capabilities. The study addressed five tasks defined by PHMSA:

- Assess past incidents to determine if additional LDS may have helped to reduce the consequences of the incident;
- Review installed and currently available LDS technologies, along with their benefits, drawbacks, and their retrofit applicability to existing pipelines;
- Study current LDS operational practices used by the pipeline industry;
- Perform a cost-benefit analysis of deploying LDS on existing and new pipelines; and
- Study existing LDS standards to determine what gaps exist and if additional standards are needed to cover LDS over a larger range of pipeline categories.

The authors of the Kiefner study were tasked only to report data and technical and cost aspects of LDS. Although the Kiefner study did not provide any specific conclusions or recommendations related to leak

[18] For natural gas and hazardous liquid pipelines, §§ 192.615(a)(3) and 195.402(e)(2), respectively.

[19] Requirements for ASV and RCV installation are at § 192.935(c), and requirements for EFRD installation are at § 195.452(i)(4).

[20] A break in the pipeline that involves the opening of the pipe in either the circumferential or longitudinal direction.

detection system standards, its content did inform this NRPM, acknowledging that pressure/flow monitoring (leak detection techniques) will consistently and reliably catch large volume, uncontrolled release events such as ruptures. Therefore, PHMSA has proposed that valves designated as rupture-mitigation valves for this rulemaking be outfitted with equipment or other means to monitor valve status, commodity pressures, and flow rates. Also, the report noted that operator procedures may have allowed ignoring alarms, restarting pumps, or opening valves during large releases.

The standard PHMSA is proposing in this rulemaking intends to reduce the frequency of these errors by requiring an operator to determine a rupture is occurring within 10 minutes following the first notification to the operator or following specific criteria involving throughput. PHMSA is considering alternate timeframes for rupture confirmation for this rulemaking. PHMSA notes that a 10-minute confirmation standard would be consistent with certain industry practices. For example, in its report following the incident near Marshall, MI, the NTSB noted that the operator had procedures in its operations manual that restricted the operation of a pipeline for longer than 10 minutes when the pipeline was operating under unknown circumstances. This procedure was adopted following a 1991 rupture and release by the same operator. PHMSA welcomes comments from stakeholders on the feasibility, reasonableness, and adequacy of the proposed 10-minute rupture confirmation standard.

The proposed accident review following these ruptures can also help drive operators to implement lessons learned system-wide and assist PHMSA in providing industry-wide guidance regarding overarching performance issues. The report may be reviewed at *http://www.regulations.gov* by searching for Docket No. PHMSA–2013–0018.

PHMSA is not proposing specific metrics to address smaller, non-rupture-type leaks in this rulemaking. PHMSA is also not proposing to require leak detection equipment on gas transmission and distribution pipelines as expansively as recommended by NTSB recommendation P–11–10, which recommended that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks. Pursuant to the findings in the Kiefner Leak Detection study, it is typically more challenging to detect smaller leaks in an operationally, technically, and economically feasible manner. Further, the report notes that LDS with the same technology, when applied to two different operating pipeline systems, can have very different results. In short, one size does not fit all, and determining a reasonable, minimum Federal standard for safety comes with several challenges. However, this NPRM, for both onshore hazardous liquid and gas transmission pipelines, would require the installation of pressure monitoring equipment at all rupture mitigation valves on both the upstream and downstream locations of the valve. This requirement incorporates an aspect of NTSB Recommendation P–11–10 that will help operators to better detect ruptures, which should drive further development and installation of leak detection technology, and may help drive operators to make decisions to improve the capabilities of their current leak detection systems to detect non-rupture type events. PHMSA continues to address the effectiveness of LDS for other non-rupture type leaks through a rulemaking,[21] engagement in new or updated standards being developed by standard developing organizations, and through the development of research and development projects.[22]

F. PHMSA 2012 R&D Forum, ''Leak Detection and Mitigation''

PHMSA sponsored a workshop on leak detection and expanded EFRD use, in Rockville, MD, on March 27–28, 2012. Additionally, a Government and Industry Pipeline Research and Development (R&D) Forum was held in Arlington, VA, on July 18–19, 2012.[23] PHMSA periodically holds 2-day R&D forums to generate a national research agenda that fosters solutions for the many challenges facing pipeline safety and environmental protection. The R&D forum allowed public, government, and industry pipeline stakeholders to develop a consensus on the technical gaps and challenges for future research. It also enabled stakeholders to discuss ways to reduce duplication of programs, consider ongoing research efforts, and leverage resources to achieve common objectives. Participants discussed the development of leak detection technology for all pipeline types (from any deployment platform) and the capabilities and limitations of current leak-detection technologies. A working group convened for the meeting for the topic of leak detection identified four gaps for future research, which were: (1) To reduce false alarms of leak detection systems; (2) leak detection technology, standards, and knowledge for new and existing systems; (3) smart system development; and (4) mobile-based leak detection system testing.

III. Proposed Rupture Identification and Mitigation Actions and Analysis of ANPRM Comments

In response to the congressional mandates contained in the 2011 Pipeline Safety Act, recommendations from the NTSB and GAO, comments received to both ANPRMs, discussions at PHMSA's public workshops, and the results of the studies and analyses described above, PHMSA is proposing standards for valve installation, rupture recognition and timely mitigation, and valve shut-off and location requirements for segment isolation. These actions are intended to minimize consequences from ruptured pipeline segments and improve the effectiveness of emergency response.

The proposed valve installation requirement applies to all newly constructed and entirely replaced gas transmission and hazardous liquid pipelines with nominal diameters of 6 inches or greater. For the purposes of this rulemaking, PHMSA proposes to define ''entirely replaced'' pipelines as those pipelines where 2 or more contiguous miles are being replaced with new pipe. Operators of these lines would be required to install automatic shutoff valves, remote-control valves, or equivalent technology at the valve spacing intervals or locations already specified in the current regulations. In the case of ''entirely replaced'' pipelines, valves that are directly associated with or are otherwise impacted by the replacement project would need to be upgraded to automatic shutoff, remote control, or equivalent valve technology. In the May 1, 1998, final order to Viking Gas Transmission,[24] PHMSA notes that § 192.13(b) states ''no person may operate a segment of pipeline [. . .] that is replaced, relocated, or otherwise

[21] Pipeline Safety: Safety of Hazardous Liquid Pipelines; 80 FR 61609; October 13, 2015.

[22] Improving Leak Detection System Design Redundancy and Accuracy, DTPH56–14–H–00007 (End: April 2017); Emissions Quantification Verification Process, DTPH5615T00012L (End: December 2017); Framework for Verifying and Validating the Performance and Viability of External Leak Detection Systems for Liquid and Natural Gas Pipelines, DTPH5615T00004L (End: March 2018)

[23] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=77.* For details on the meeting, please see the summary report at *https://primis.phmsa.dot.gov/rd/mtgs/071812/2012_RD_ForumSummaryReport.pdf.*

[24] *In the Matter of Viking Gas Transmission,* Final Order, C.P.F. No. 32102 (May 1, 1998).

changed [. . .], unless the replacement, relocation, or change has been made according to the requirements in [part 192].'' In that final order, PHMSA stated it expected the operator to ensure that any future pipeline replacements comply with the valve spacing requirements at § 192.179. Therefore, even if a replaced segment does not have a valve, operators would need to ensure that the replaced segment meets the spacing requirements at § 192.179 and would need to ensure, per this rulemaking, that any valves installed for compliance also meet the standard of being automatic shut-off, remote-control, or equivalent technology. In the case of hazardous liquid pipelines, maximum valve spacing mileages are not specified under the current regulations, and PHMSA has proposed valve spacing for those pipelines constructed following the issuance of the final rule. The valves installed per the NPRM's provisions for both gas transmission and hazardous liquid pipelines would also be subject to the 40-minute rupture-mitigation closure requirement and the monitoring requirements of the rulemaking.

These proposed rupture identification and mitigation regulations include: (1) Defining the term ''rupture'' as a significant breach of a pipeline that results in a large-volume, uncontrolled release of commodity that can be determined according to specific criteria or that has been observed and reported to the operator; (2) a requirement to establish procedures specifically for responding to a rupture based on the definition; (3) a requirement to declare a rupture as soon as practicable but no longer than 10 minutes after initial notification or indication; (4) a requirement to immediately and directly notify the appropriate public safety answering point (9–1–1 emergency call centers) for the jurisdiction in which the rupture is located; and 5) a requirement to respond to a rupture as soon as practicable by closing rupture-mitigation valves, with complete valve shut-off and segment isolation within 40 minutes after rupture identification. Rupture identification occurs when a rupture is reported to, or observed by, pipeline operating personnel or a controller.

The term ''rupture-mitigation valve,'' as it pertains to this proposal, means the specific valve(s) that the operator would use to isolate a pipeline segment that experiences a rupture—the applicable ''shut-off segment'' as specified in this NPRM. These valves can be any combination of ASVs, RCVs, or equivalent technology upon review by PHMSA, and they would be required to comply with the proposed new rupture mitigation timing, testing, communication, maintenance, and inspection requirements of this NPRM. PHMSA is also proposing operators periodically verify, through drills, that their rupture-mitigation valves can reliably meet the standard outlined above and that any communications equipment necessary for valve actuation functions as needed. Additionally, operators would be required to perform post-accident reviews of any ruptures or other release events involving the closure of rupture-mitigation valves to ensure these proposed performance objectives are met and that any lessons learned can be applied system-wide.

Regarding the proposal for immediately and directly notifying the appropriate public safety answering point (PSAP) for the jurisdiction in which the rupture is located, per PHMSA's Advisory Bulletin published on October 11, 2012 (77 FR 61826), PHMSA believes that immediate communication should be established between pipeline facility operators and PSAP staff when there is any indication of a pipeline rupture or other emergency condition that may have a potential adverse impact on public safety or the environment. PHMSA recommends that pipeline facility operators ask their applicable PSAP(s) if there are any other reported indicators of possible pipeline emergencies such as odors, unexplained noises, product releases, explosions, fires, etc., as these reports may not have been linked to a possible pipeline incident by the callers contacting the 9–1–1 emergency call center. This early coordination will facilitate the timely and effective implementation of the pipeline facility operator's emergency response plan and coordinated response with local public safety officials.

PHMSA is not proposing specific metrics to address smaller, non-rupture-type leaks in this NPRM. PHMSA is also not proposing to require leak detection equipment on gas transmission and distribution pipelines as specifically recommended by NTSB recommendation P–11–10. Pursuant to the findings in the Kiefner Leak Detection study, it is typically more challenging to detect smaller leaks on pipelines in an operationally, technically, and economically feasible manner. However, this NPRM, for both hazardous liquid and gas transmission pipelines, requires the installation of pressure monitoring equipment at all rupture mitigation valves on both the upstream and downstream locations of the valve, which will help operators to better detect ruptures and which can be used for leak detection when leak detection technology becomes further developed. PHMSA continues to address the effectiveness of leak detection systems for other non-rupture type leaks through other rulemakings, R&D projects, and engagement in new or updated standards being developed by standard developing organizations.

The rupture-mitigation provisions of this NPRM, and the related comments to the major topic areas of this NPRM, are discussed below:

A. Definition of Rupture

Section 4 of the 2011 Pipeline Safety Act requires PHMSA to, if appropriate, issue regulations requiring the use of ASVs or RCVs, or equivalent technology, where economically, technically, and operationally feasible, on newly constructed or entirely replaced transmission pipeline facilities. PHMSA notes, though, that there may be little benefit to the installation of these valves if there is not a threshold requiring their use to mitigate the consequence of large releases.

While some individual operators have installed ASVs and RCVs in response to recent high-profile incidents, and existing regulations require operators to consider these types of valves as additional mitigative measures in HCAs, the continued occurrence of incidents with unnecessarily slow response times suggests that operators may not be fully accounting for the social costs of unmitigated large-scale release events in their risk analysis, emergency planning, and valve automation decisions. PHMSA is proposing a new definition for the term ''rupture'' for both natural gas and hazardous liquid pipelines in parts 192 and 195, respectively, that operators must properly identify and subsequently take mitigative action against as proposed in this NPRM.

The term ''rupture,'' as defined and applied in these proposed regulations, is meant to encompass any type of large-volume, rapidly occurring, and uncontrolled release or failure event. Ruptures would include events that have rupture-like characteristics in terms of pressure and flow profiles, including but not limited to failures due to mechanical punctures, line breaks and other large-scale failures, seam splits, large through-wall cracks, sheared lines due to natural or other outside force damage, and valves inadvertently left open.

A rupture, as defined in this NPRM, would include any of the following events that involve an uncontrolled release of a large volume of product over a short period of time: An unanticipated or unplanned pressure loss of 10 percent or more, occurring within a time interval of 15 minutes or less (with certain specific exceptions relevant to gas and liquid pipelines); an unexplained flow-rate change, pressure change, instrumentation indication, or equipment function; and an apparent large-volume, uncontrolled release of gas or a failure observed by operator personnel, the public, or public authorities. The term ''rupture'' as defined in this NPRM is only applicable as it would pertain to the proposed regulations in parts 192 and 195 and should not be confused with the term ''rupture'' as it is utilized in other PHMSA applications, such as in incident and accident reporting forms and other general PHMSA documents and records. For the purposes of those other applications, operators should consult the instructions for those forms to find the definition of ''rupture,'' as it will be distinct from the term's proposed use in parts 192 or 195 per this rulemaking. PHMSA welcomes comment on this proposed definition of rupture and the usages of the term as they are proposed.

Although there are key differences in the behavior of gas pipeline ruptures and hazardous liquid pipeline ruptures, prompt identification, rapid system shutdown, and segment isolation are objectives common to both. Both types of ruptures have increased risks of adverse consequences as the time lengthens for both system shutdown and segment isolation. In the case of hazardous liquid pipelines, the volume of product released increases and spreads further over the surrounding terrain or in water as response and isolation times are prolonged, which significantly increases the potential for adverse consequences. As it can take an area affected by a hazardous liquid spill months or even years to be restored to a pre-accident state, limiting the amount of product released and the size of the affected area are of great importance.

For gas pipelines, a rupture results in a sudden release of energy that is sustained for longer periods of time even after the system is shut down, as the pressurized gas expands into the atmosphere and remains in relative proximity to the failure site in most cases. When gas ruptures ignite, the length of time that the gas pipeline is not shut down and isolated leads to consequences, such as fires, that may otherwise be containable but spread outward and cause significant additional damage beyond the immediate impact zone.

In both cases, the quick isolation of a ruptured segment does not significantly alter the immediate impact of the rupture even though the extended consequences can be significantly reduced.[25] Therefore, this rulemaking is expected to drive improvement in rupture response and isolation times to reduce a rupture's extended consequences.

The rupture-mitigation requirements of any final rule that are based on the new rupture definition would take effect 12 months after the rulemaking becomes effective, and the definition itself would be incorporated with the other definitions for parts 192 and 195 in § 192.3 for onshore gas transmission pipelines and in § 195.2 for onshore hazardous liquid pipelines, respectively.

B. Accident Response and Mitigation Measures

i. Installing RCVs and ASVs

Several operators and industry trade groups, including INGAA, AGA, American Public Gas Association (APGA), Atmos, MidAmerican, Dominion East Ohio, and TransCanada, noted in the ANPRM that installing RCVs and ASVs will not prevent incidents and that existing requirements allow for safe and reliable service. Chevron commented that operators should have the flexibility to select the most effective measures based on specific locations, risks, and conditions of the pipeline segment. PHMSA notes that, following the San Bruno incident, PG&E rapidly installed ASVs where possible and stated there was sufficient basis to deploy such valves; according to a CPUC press release, the workplan it approved for PG&E would install 228 automated shut-off valves from 2012–2014.[26 27] In comparison, in 2006, PG&E concluded that most of the damage from a rupture would take place in the first 30 seconds before shut-off valves could stop the flow of gas.[28] Gas transmission operators have previously cited a Gas Research Institute study from 1998 as the basis for concluding that the installation of RCVs is not cost-effective since, in most cases, injury or death occurs so near to the time of pipeline rupture that RCVs may not respond quickly enough. A PG&E internal memorandum from 2006 (subsequently released to the public) documenting its consideration of installing ASVs and RCVs on lines pointed to this study when concluding that the use of an ASV or RCV as a prevention and mitigation measure in an HCA would have ''little or no effect on increasing human safety or protecting properties,'' and did not recommend using either as a general mitigation measure.[29]

However, the NTSB investigation of the San Bruno incident and research by ORNL suggests there are real benefits to more rapid valve closure due to faster emergency response. As the NTSB stated, the total heat and radiant energy released by the burning gas was directly proportional to the time gas flowed freely from the ruptured pipeline. Because the operator took 95 minutes to stop the flow of gas and isolate the rupture, the natural gas-fed fire continued to ignite homes and vegetation, contributing to the extent and severity of property damage and increasing the life-threatening risks to residents and emergency responders. It wasn't until 95 minutes after the rupture that firefighters could safely approach the rupture site and begin containment efforts due to the intensity of the fire. Firefighting continued for 2 days after the flow of gas stopped, and over 900 emergency responders were deployed. The use of ASVs or RCVs would have reduced the amount of time taken to stop the flow of gas and would have shortened the time the site was inaccessible to emergency responders.

Additionally, studies have indicated that a prolonged gas-fed fire leads to increased property damage, including two separate studies from the Gas Research Institute,[30] as well as a 1999 study from RSPA stating that RCV use could reduce property damage, reduce public disruption of product supply, reduce damage to other utilities, and allow emergency responders faster access to the accident site.[31]

[25] Oak Ridge National Laboratory; ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety;'' ORNL/TM–2012/411; October 31, 2012; Section 5, pgs. 175–186.

[26] Carey and Rogers. 2011. PG&E officials grilled about automatic shut off valves. Silicon Valley MercuryNews.com, *http://www.mercurynews.com/san-bruno-fire/ci_17510209?nclick_check=1,* posted 3/1/11.

[27] California Public Utilities Commission. 2012. ''CPUC Approves Pipeline Safety Plan for PG&E; Increases Whistleblower Protections.'' *http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K531/40531580.PDF*

[28] Carey and Rogers. 2011. PG&E officials grilled about automatic shut off valves. Silicon Valley MercuryNews.com, *http://www.mercurynews.com/san-bruno-fire/ci_17510209?nclick_check=1,* posted 3/1/11.

[29] NTSB Accident Report; NTSB/PAR–11/01; PG&E Natural Gas Transmission Rupture and Fire; San Bruno, California; September 9, 2010; Pgs. 56–57.

[30] M. Stephens, ''A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines,'' GRI–00/0189, Gas Research Institute, October 2000; and C.R. Sparks, ''Remote and Automatic Main Line Valve Technology Assessment,'' Gas Research Institute, July 1995.

[31] Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility Determination Mandated by the Accountable Pipeline Safety and

PHMSA is proposing to implement the section 4 mandate from the 2011 Pipeline Safety Act by requiring newly constructed and entirely replaced natural gas transmission and hazardous liquid pipelines with nominal diameters of 6 inches and greater be equipped with remote-control valves, automatic shutoff valves, or equivalent technology, at distances specified under the valve spacing requirements per the current regulations.

For newly constructed pipelines of certain diameters and replaced pipelines of certain diameters and specific lengths, this NPRM would require rupture-mitigation valves located on both sides of a ''shut-off segment,'' which is defined in this NPRM as the applicable segment of pipe between the valves closest to the endpoints of a high consequence area or Class 3 or 4 location. For hazardous liquid pipelines, any mainline valve located within a shut-off segment would be a rupture-mitigation valve. For gas transmission pipelines, maximum valve spacing for shut-off segments would apply based on class location factors.

Comments from pipeline operators and industry organizations point to a wide disparity in the percentage of sectionalizing valves that are RCVs or ASVs. This may reflect the use of very different decision criteria by different operators for determining when RCVs or ASVs should be installed. PHMSA determined a need for clarity in the criteria for rupture mitigation and segment isolation to ensure that valve configurations are capable of adequately mitigating the potential consequences of rupture releases, as discussed below.

ii. Standards for Rupture Identification and Response Times

In this NPRM, PHMSA proposes requirements for rupture response and mitigation that would require operators of certain pipeline segments to: (1) Determine the existence of a rupture within 10 minutes of initial identification; (2) make immediate and direct notification to the appropriate public safety answering point (9–1–1 emergency call centers); (3) initiate rupture-mitigation valve closure as soon as practicable after identifying a rupture; and 4) complete rupture-mitigation valve shut-off (closure and rupture segment isolation) as soon as practicable but within a maximum time interval of 40 minutes after rupture identification.[32] Operators may meet this standard using ASVs, RCVs, or equivalent technologies upon review by PHMSA. This NPRM also proposes that operators conduct regular emergency drills and inspections to confirm the performance of operator systems, processes, procedures, and personnel to achieve this standard.

In the hazardous liquid ANPRM, the American Petroleum Institute (API), Association of Oil Pipelines (AOPL), the Texas Oil and Gas Association (TxOGA), Louisiana Midcontinent Oil & Gas Association (LMOGA), and TransCanada Keystone Pipeline commented that there is no current industry standard setting a maximum spill volume or valve activation timing due to the widespread variation in pipeline dynamics, and it therefore would be difficult to establish a one-size-fits-all requirement for these items. API and AOPL suggested PHMSA should focus on prevention and response rather than reducing spill size.

PHMSA agrees with the commenters that spill prevention and response are important to ensuring the safety of hazardous liquid pipelines and that establishing a one-size-fits-all maximum spill volume would be extremely challenging due to a variety of factors, including different pipeline diameters, terrain surrounding pipelines, commodity type, operating conditions, sensitivity of the surrounding areas, and types and nature of flow paths. However, based on previous incident history, PHMSA has determined that it is necessary to define standards to ensure operators identify ruptures when they occur and promptly shut off mainline valves and isolate the ruptured pipeline segment. As a result, PHMSA is proposing to require operators to base their decisions upon documented procedures that take into account unexplained flow rate changes, pressure changes, instrumentation indications, and equipment functions. Factoring this information into the decision-making processes, when paired with additional pressure sensors located along the pipeline and valves that can be closed quickly after rupture detection, should help mitigate the effects of pipeline ruptures. For instance, such requirements would have helped mitigate the PG&E incident at San Bruno, CA, and the Enbridge incident near Marshall, MI, because the operators would have been in a better position to identify the ruptures if they were monitoring for the required information.

The GAO report referenced in Section II of this NPRM noted that performance-based goals established with reliable data and sound agency assessments could result in improved operator response with ASV and RCV use. The report also states that although existing PHMSA regulations for operator response and ASV and RCV use are performance-based, they are ''not well-defined.'' Specifically, parts 192 and 195 currently require operators to respond to incidents and accidents in a ''prompt and effective manner'' (§§ 192.615(a)(3) and 195.402(e)(2)). As mentioned earlier, however, identical response actions are not appropriate for all circumstances due to the specific and highly variable location, equipment, and operating conditions involved on individual pipeline systems. The GAO noted some organizations in the pipeline industry believe that some form of performance-based goals can allow operators to identify actions that could improve their ability to respond to accidents, including ruptures, more consistently and in a timelier manner, and those organizations are taking steps to implement this approach. PHMSA agrees that a more precise regulation specific to ruptures would be effective in improving operator response times and mitigative actions because ruptures have recognizable operational signatures and, hence, more clearly defined triggers and actions that operators can take in response.

iii. Using RCVs or ASVs in All Cases

In the hazardous liquid and gas transmission ANPRMs, PHMSA asked stakeholders to comment on whether the Pipeline Safety Regulations should include a requirement mandating the use of RCVs in all cases. The NTSB reinforced, via a submitted comment, that PHMSA should adopt requirements consistent with its recommendations P–11–10 and P–11–11. The NTSB noted in its analysis of the San Bruno incident that if PG&E could have shut off the gas flow of its ruptured segment sooner than 95 minutes, it would have likely resulted in a smaller fire of shorter duration as well as less risk to residents, their property, and first responders. The ORNL report and the GAO report referenced in this rulemaking reached conclusions similar to the NTSB's for both gas transmission and hazardous liquid pipelines. In other comments, Metro Area Water Utility Commission (MAWUC) indicated that PHMSA should consider requiring all valves to be remotely controlled but that its decision should be based on an analysis of benefits and risks. North Slope Borough (NSB) supported the use of

Partnership Act of 1996); September 1999; *https://rosap.ntl.bts.gov/view/dot/16918/dot_16918_DS1.pdf?*.

[32] As defined in this NPRM, rupture identification occurs when a rupture is observed by or reported to pipeline operating personnel or a controller.

RCVs in all instances. A private citizen commented that PHMSA should issue regulatory language requiring RCVs for poison inhalation hazard pipelines. Conversely, comments from industry groups and pipeline operators stated that the benefits of requiring all valves to be remotely controlled would be dependent on local factors, and such additional requirements would add to pipeline system complexity and increase the probability of failure.

In consideration of the comments received, PHMSA has determined that a requirement for all valves to be automatically or remotely controlled would not be feasible due to several technical concerns, including a lack of space for actuator and communication equipment in urban areas, no communications signal in certain areas, and the potential for vandalism. The ORNL report came to a similar conclusion in that it was technically feasible to install ASVs and RCVs provided there was sufficient space for the valve body, actuators, power source, sensors, related electronic equipment, and the appropriate personnel required to install and maintain the valves.

Further, PHMSA determined that it would be most reasonable for newly constructed or entirely replaced natural gas transmission and hazardous liquid pipelines with diameters of 6 inches or greater to be subject to the valve installation requirement per the Section 4 mandate in the 2011 Pipeline Safety Act. While it is technically possible for lines as small as 2 or 4 inches to have automatic shutoff or remote-control valves, the potential impact radii and release volumes would be smaller under those scenarios, and PHMSA would not expect there to be benefits commensurate with the costs of installing the valves. However, PHMSA would like comment on whether these assumptions are reasonable.

Therefore, PHMSA is addressing the mandate in the 2011 Pipeline Safety Act by proposing a valve installation requirement on newly constructed and entirely replaced gas transmission and hazardous liquid pipelines, as well as proposing a standard for rupture identification and mitigation in areas of higher consequence. Alternatives considered by PHMSA are documented in the PRIA filed under Docket No. PHMSA–2013–0255 at *http://www.regulations.gov.*

Several commenters on the gas transmission and hazardous liquid ANPRMs, including industry trade groups and pipeline operators, opposed a requirement that all sectionalizing valves be capable of being controlled remotely. As some commenters pointed out, RCVs or ASVs may not be warranted in many situations because of specific local conditions that could limit the safety benefits of such a requirement. The ORNL report also concluded that site-specific parameters can influence risk analyses and feasibility evaluations, and they can often vary significantly from one pipeline segment to another.

Recent high-profile pipeline construction projects show a wide use of ASVs and RCVs, which demonstrates the feasibility and prevalence of these technologies. The interstate transportation of energy products, including natural gas, is subject to economic regulation by the Federal Energy Regulatory Commission (FERC). New gas transmission pipeline construction projects and significant changes to existing pipelines are therefore subject to FERC review and environmental analysis requirements under the National Environmental Policy Act. Final Environmental Impact Statements (EIS) published or approved after the 2011 Pipeline Safety Act have included some commitment to use ASVs or RCVs on new or upgraded gas transmission pipelines subject to FERC approval. The wide use of this technology demonstrates the feasibility and prevalence of the use of powered actuators or otherwise remote-controlled valves.

For instance, the Southeast Market Pipelines Project [33] intended to equip all 63 mainline block valves with ASVs or RCVs within three connected natural gas transmission pipeline projects in Florida, Alabama, and Georgia. Similarly, per the Rover Pipeline final EIS,[34] all 78 mainline block valves for the Rover Pipeline and related projects would be equipped for remote operation from the control center. The PRIA for this NPRM contains further information on this topic under Section 4.4—Valve Automation.

Further, recent high-profile hazardous liquid pipeline construction projects also show use of RCVs. The final EIS for TransCanada's proposed Keystone XL Pipeline project indicated that 71 out of 112 intermediate mainline valves along the route would be remotely operated block valves, while an additional 24 valves would be designated as check valves (U.S. Department of State, 2011). The North Dakota Public Service Commission reported that the Dakota Access Pipeline design includes remote actuators on all mainline valves in the State of North Dakota (North Dakota Public Service Commission, 2016).

However, as stated before, PHMSA understands there may be technical challenges to requiring the use of automation in certain cases. Specifically, PHMSA is aware that there might not be the space necessary for operators to install equipment needed for an ASV or an RCV, and PHMSA also realizes that in certain areas, operators might not be able to get the necessary communications signal to ASVs or RCVs so they work as intended. Therefore, a one-size-fits-all valve-type installation requirement may not be feasible. As such, PHMSA is proposing a rupture-mitigation valve standard that provides operators flexibility to install RCVs, ASVs, or an equivalent technology. Alternatively, operators may use manual valves where it is not economically, technically, and operationally feasible to use RCVs, ASVs, or an equivalent technology. This flexibility will allow operators to choose the most appropriate valve based on the unique circumstances at each location, while still ensuring that such valves will close as soon as practicable but no later than 40 minutes after a rupture is identified.

PHMSA welcomes any comments that stakeholders might have regarding the reasonability of the proposed 40-minute valve closure time based on current technologies and capabilities. When considering an appropriate valve closure time for this rulemaking, PHMSA noted that many natural gas transmission and hazardous liquid systems can have several junctions where product arrives and departs or where multiple pipelines are connected with each other in a series of looped lines. On these more complicated pipeline systems, operators implementing shutoff procedures may need to consider factors including the potential effects on pipeline systems flowing into a pipeline needing to be isolated, the restriction of downstream deliveries to vital customers, and the impacts of the complete isolation of looped common-use systems. Therefore, establishing a one-size-fits-all requirement for valve closure times on all natural gas transmission and hazardous liquid pipeline systems can be challenging.

When developing the proposed valve-closure time in this NPRM, PHMSA considered its work on the ''Alternative MAOP'' rulemaking and the requirements in that rule for operators to install RCVs and close valves within

[33] FERC, 2015. Southeast Market Pipelines Project, Final EIS, Office of Energy Projects. Volume 1, Section 2.6.1. *https://www.ferc.gov/industries/gas/enviro/eis/2015/12-18-15-eis.asp*

[34] FERC, 2016. Rover Pipeline, Panhandle Backhaul, and Trunkline Backhaul Projects, Final EIS. Volume 1, Section 2.2.2. *https://www.ferc.gov/industries/gas/enviro/eis/2016/07-29-16-rover-pipeline.asp.*

60 minutes on applicable pipeline segments.[35] PHMSA also considered its work on recent special permits and conditions in those permits for single, non-looped pipelines to have valves that can close within 30 minutes. Further, PHMSA notes that in the ANPRM stages of the Safety of Hazardous Liquid Pipelines and the Safety of Gas Transmission Pipelines rulemakings, PHMSA considered valve closure times of 30 minutes for both natural gas transmission and hazardous liquid pipelines, and certain industry commenters representing gas pipeline operators proposed times of 60 minutes.

In this NPRM, PHMSA is proposing to require operators to close the necessary valves ''as soon as practicable'' following rupture identification with a 40-minute-maximum closure time because 40 minutes represents a reasonable outer limit to provide time, if needed, for operators to get personnel on-site to close any necessary valves. However, PHMSA expects RCVs or ASVs in most instances to be shut off in a much shorter timeframe.

PHMSA determined the 40-minute closure time as follows:

Locating the rupture: Once an operator confirms a rupture is occurring, an operator needs to determine the location of the rupture. As a part of this process, control personnel would identify the location of the mainline valves needing to be shut as well as any crossover valves and other pipeline systems that flow into or out of the impacted pipeline system. Control personnel would then identify the systems needing to be isolated, if any, and the locations of the valves necessary to do so. If any of these systems are operated by a different operator, those operators must be notified so that deliveries can be re-routed and so that deliveries are not restricted to critical customers such as hospitals or power plants. Following the rupture being located, control personnel would dispatch operating personnel to the rupture site, mainline valve locations, and any other critical pipeline locations. Those operating personnel would communicate and collaborate with local emergency responders to minimize the impact to the public and environment and identify safety needs. Further, operators must notify other parties, including local distribution companies, operators of directly connected pipelines, power plants, and direct-feed manufacturing facilities to ensure that rapid valve closures do not cause emergency cascading events due to increased pressures, surges, or the lack of energy product. PHMSA has estimated these actions will be completed anywhere between 5 and 15 minutes of rupture identification.

Isolating the ruptured segment: An operator will begin closing the appropriate valves once a rupture is identified and located. This might include mainline valves, any crossover valves, and valves to other pipeline systems that flow into or out of the ruptured pipeline system. Operating personnel would continue to work with emergency responders to minimize the impact to the public and identify safety needs. If a valve fails to close, the local pipeline operating personnel would close it. PHMSA notes that RCV shutdown times will vary based on size, whether it is a ball or gate valve, the actuator type, and the operating pressure at the time of closure, which will depend on how close it is located to the rupture site. ASV shutdown times will vary based on the preceding factors as well as the minimum pressure or the rate of pressure change at the mainline valve. All pipeline system valve shutdown times require the consideration of the valve closure timing and its impact on maximum operating pressures and surge pressures from the speed of valve closure on the pipeline system and any laterals or other pipeline systems connected to the ruptured pipeline. Under emergency conditions and given operating pressures, PHMSA estimates an RCV can be closed within 5 to 15 minutes after rupture identification and location, an ASV can be closed within 10 to 25 minutes after rupture identification, and a valve needing some type of manual actuation could be closed within 15 to 25 minutes after rupture identification.

Based on this analysis, PHMSA is proposing a maximum 40-minute valve closure period; however, PHMSA welcomes comments regarding whether this timeframe could be reasonably lowered so that segments are isolated more quickly and ruptures are mitigated faster, or whether there are other reasons that would preclude an operator from confirming a rupture and closing an ASV, RCV, or equivalent valve within 40 minutes after the identification of a rupture. Similarly, PHMSA welcomes comment on the 40-minute closure limit as it applies to any manual valves that operators might need to install because installing ASVs, RCVs, or equivalent technology is not feasible.

PHMSA also notes that the ''Alternative MAOP'' final rule published on October 17, 2008, which affects gas transmission pipelines, finalized a requirement to provide remote valve control through a SCADA system, other leak detection system, or an alternative method of control. This requirement applies if personnel response time to mainline valves on either side of an HCA exceeds 1 hour (under normal driving conditions and posted speed limits) from the time an emergency event is identified in the operator's control room. PHMSA welcomes comment on whether it should revise the Alternative MAOP rule's requirements to match this rulemaking's proposed 40-minute response time, or whether this rulemaking should be made consistent with the Alternative MAOP rule and establish a 60-minute response time following rupture identification.

C. Drills To Validate Valve Closure Capability

In response to the hazardous liquid ANPRM, Texas Pipeline Association (TPA) and others commented that requiring additional valve automation could result in an increased probability of valve or system failure. PHMSA agrees that the addition of any type of engineered equipment is accompanied by a potential for mechanical or operational failure. This rule proposes inspection and maintenance provisions to minimize this possibility. These inspection and maintenance provisions would apply to procedures and equipment that should be in use to isolate pipeline segments in the event of potential incidents. More specifically, PHMSA proposes to require that operators conduct initial and periodic validation drills to ensure that valves designated for rupture mitigation will close to ensure that the response and shut-off times of this proposal can be reliably and consistently achieved. PHMSA is also proposing demonstration and verification requirements, including point-to-point verification tests for RCVs, to ensure that communications equipment works. New provisions proposed in this NPRM would also require that any deficiencies be identified and corrected within a fixed period, and that any lessons learned during these drills be applied system-wide to ensure adequate performance in future emergencies. PHMSA has proposed these requirements because any newly installed valve systems will require regular maintenance activities and emergency drills to ensure they operate as intended per the proposals in this rulemaking.

[35] ''Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines; Final Rule;'' October 17, 2008; 73 FR 62148.

The ORNL report discussed in Section II of this NPRM documented the reliable operation of ASVs and the importance of operating procedures in ensuring the reliability of RCVs. The report noted that, in areas that are susceptible to electrical power outages, reliability is a potential concern, and redundant, alternative, or backup power sources may be required to ensure continuous availability of electricity for motors, solenoids, and electronic components. Proper valve maintenance involving seat and valve-body cleaning, packing and gasket replacement, and valve closure testing to ensure that ASVs actuate on command and close completely, are issues that influence operational feasibility. As PHMSA notes throughout this NPRM, rupture-mitigation valves must function properly when needed following an identified rupture to quickly mitigate the consequences of pipeline ruptures, including property and environmental damage. The drill requirements are proposed in § 192.745 for onshore gas transmission pipelines and § 195.420 for onshore hazardous liquid pipelines.

D. Maximum Valve Spacing Distance

i. Gas Transmission Pipelines

Existing regulations for gas transmission pipelines at § 192.179 already contain provisions for maximum valve spacing based on class location. This NPRM proposes supplementary requirements for rupture-mitigation valve spacing in newly defined ''shut-off segments'' on newly constructed or replaced onshore gas transmission pipelines.

These ''shut-off segments'' are segments of pipe between the upstream mainline valves closest to the upstream endpoints of the HCAs or Class 3 or 4 locations and the downstream mainline valves closest to the downstream endpoints of the HCAs or Class 3 or 4 locations so that the entirety of the applicable HCA or Class 3 or 4 location is contained between a set of rupture-mitigation valves. A shut-off segment can contain multiple HCAs or Class 3 or 4 locations—an operator of such a segment would need to ensure that the entirety of the contiguous class locations and HCAs are within a set of rupture-mitigation valves. Shut-off segments also extend to the nearest mainline valves of any crossover and lateral pipe that connects to the shut-off segment between the furthest upstream and downstream mainline valves. All valves on shut-off segments would be identified as ''rupture-mitigation valves'' for the purposes of this rulemaking and its proposed provisions so that, when closed, there is no flow path for gas to be transported to the rupture site (except for any residual gas already in the ruptured shut-off segment).

In this NPRM, PHMSA proposes that the distance between rupture-mitigation valves for each shut-off segment must not exceed 8 miles for shut-off segments containing a Class 4 location (with or without an HCA), 15 miles for a shut-off segment containing a Class 3 location (with or without an HCA), and 20 miles for a shut-off segment containing HCAs in Class 1 or 2 locations. These proposed rupture-mitigation valve spacing requirements for shut-off segments are in accordance with §§ 192.179 and 192.611 for pipeline class location segments that have had a one-class class location change (a Class 1 to a Class 2, a Class 2 to a Class 3, or a Class 3 to a Class 4 change) and meet the criteria under § 192.611(a) for a ''one class change bump.'' This allows operators to use the valve spacing required in § 192.179 for the previous class location when creating shut-off segments where the class location has recently changed. Shut-off segments containing different class locations or HCAs must have valve spacing equivalent to the spacing, as provided above, for the most stringent class location in the shut-off segment.

In response to questions in the gas transmission ANPRM related to valve spacing, INGAA contended that while valve spacing and selection are important factors in incident response, public safety requires integrated planning and implementation for detecting ruptures and closing valves, which INGAA called an ''Incident Mitigation Management'' (IMM) plan in its comments. INGAA described IMM as a holistic performance-based means of detecting and responding to pipeline failures with some similarities to the proposals in this NPRM. INGAA contends that IMM plans should cover various aspects of response, including how operators detect failures, how they place and operate valves, how they evacuate gas from pipeline segments, and how they prioritize coordination efforts with emergency responders.

Conversely, Accufacts contended that existing spacing requirements are inadequate and suggested that further regulation is required concerning the placement, selection, and choice of RCVs, ASVs, or equivalent technology. They stated that valve spacing and closure play a significant role in depressurizing a gas pipeline segment after a rupture, thereby limiting the total volume of gas released in an incident. The Pipeline Safety Trust also supported the installation of additional valves on gas transmission pipelines to reduce consequences following large-scale incidents. A private citizen suggested that valves be required at 1-mile intervals in densely populated urban areas and that they close automatically in the event of an incident.

PHMSA agrees with certain commenters that the mere installation of additional valves, including RCVs or ASVs, will not reduce the frequency of gas transmission pipeline releases. The mere presence of a valve will not prevent an incident from occurring. However, PHMSA disagrees with the same commenters who assert that additional valves do not reduce the consequences after such releases, as prompt rupture identification, response, and segment isolation through valve shut-off are key factors in limiting and reducing incident consequences. As discussed throughout this NPRM, PHMSA has determined that prompt operator rupture identification and mitigation, which includes the isolation of the rupture or failed segment as soon as practicable, are important factors that can contribute to reduced consequences.

ii. Valve Spacing in Response to Class Location Changes

In addition to the valve spacing requirements listed above related to shut-off segments, PHMSA is also proposing that operators be required to add valves if necessary to meet the applicable valve spacing requirements when changes to class location occur that require pipe replacement. PHMSA notes that a gas pipeline's class location broadly indicates the level of potential consequences for a pipeline release. Section 192.179 currently requires closer valve spacing for higher class locations. Areas of potentially higher consequences (*i.e.,* HCAs) can be in lower class locations as well. HCAs in Class 1 or Class 2 locations include pipeline segments where a release could have severe consequences similar to a release in Class 3 and Class 4 areas. In HCAs, operators are required to provide additional protection in accordance with the integrity management requirements of part 192, subpart O.

There were several comments related to new valve installations in the event of a class location change so that those valves meet the spacing requirements of § 192.179. The Gas Piping Technology Committee (GPTC), AGA, INGAA, and several of INGAA's members (MidAmerican, Paiute, and Southwest Gas) opposed applying § 192.179 requirements retroactively to class location changes. Commenters also expressed opinions that the existing regulations are adequate. However, the Commissioners of Wyoming County, Pennsylvania and CPUC commented that regulations should require additional valves when population increases and class locations change. Additionally, Accufacts suggested that new mainline valves should be installed when a site becomes an HCA regardless of class location, but a reasonable time should be allowed for such valves to be installed and become operational.

Valve spacing requirements in § 192.179 are based upon the class location. When a pipeline class location changes because of additional development near a pipeline, this increases both the potential consequences of a release and the potential benefits of closer valve spacing for consequence mitigation. PHMSA proposes to only require that valve spacing be made to match the requirements in § 192.179 for a new class location when pipe replacement is necessary in response to a class location change, such as a Class 1 to Class 3, or a Class 2 to Class 4. Note that this requirement would be consistent with the 1998 Final Order for Viking Pipeline,[36] which required class location changes to meet the mainline valve spacing as defined in § 192.179 and the installation of a sectionalizing valve based upon the class location in a ''replaced pipeline segment.'' Under this approach, when a class location change is implemented using only a pressure test in accordance with § 192.611 but without pipe replacement, then additional valve installation would not be required.[37] This approach will better balance the potential benefits from mitigating consequences of releases because of closer valve spacing with the costs of installing new valves, costs that will be lower if operators install additional valves in the context of installing new pipe for a class location change.

iii. Hazardous Liquid Pipelines

For onshore hazardous liquid pipelines, existing regulations establish valve location requirements for certain pipeline facilities and locations, such as at pump stations, breakout storage tanks, lateral takeoffs, certain water crossings, public water reservoirs, and for other locations as appropriate, based on terrain, location of populated areas, and other factors. However, a maximum distance for valve spacing for new pipelines is not currently specified. In response to the hazardous liquid ANPRM, several industry groups and individual operators noted that ASME B31.4, a consensus industry standard published by the American Society of Mechanical Engineers (ASME), includes a maximum valve spacing requirement of 7½ miles for liquefied petroleum gas and anhydrous ammonia pipelines in populated areas. Specifically, these commenters stated that valve spacing varies, that most mainline valves are manually operated, that check valves are used in certain cases, and that some remotely controlled valves had been added because of the integrity management requirements.

PHMSA also asked for public comment on how the agency should apply any new valve location requirements developed for hazardous liquid pipelines. API and AOPL, supported by TransCanada Keystone Pipeline, LMOGA, and TxOGA, indicated that valve spacing requirements should not be changed, and that specifying valve location requirements retroactively would be difficult and confusing. Further, these commenters indicated that requiring the retrofitting of existing lines to meet any type of new requirement would be expensive for industry, create environmental impacts, lead to potential construction accidents, and may cause possible interruptions of service. MAWUC and NSB commented that any new valve locations or remote actuation regulations should be applied to new pipelines or existing pipelines that are repaired.

In this NPRM, PHMSA is proposing that newly constructed and entirely replaced hazardous liquid pipelines with nominal diameters of 6 inches or greater have automatic shutoff valves, remote-control valves, or equivalent technology spaced in accordance with the existing hazardous liquid valve location provisions and the valve spacing requirements proposed in this rulemaking, as there are no current valve spacing requirements in the regulations for hazardous liquid pipelines.

For newly constructed onshore hazardous liquid pipelines that could affect HCAs or for hazardous liquid pipelines in areas that could affect HCAs and where 2 or more contiguous miles have been replaced, PHMSA is proposing a maximum valve spacing of every 15 miles. PHMSA based this spacing mileage, in part, off of Class 2 requirements for natural gas pipelines. Additionally, PHMSA believes that, given the current guidelines operators must consider regarding local terrain and drain-down volumes, a maximum spacing of 15 miles for valves in HCAs would be reasonable.

For newly constructed onshore highly volatile liquid (HVL) pipelines in high population areas or other populated areas, as those terms are defined in § 195.450, or for HVL pipelines in those areas where 2 or more contiguous miles have been replaced, PHMSA is proposing a maximum valve spacing of every 7½ miles. PHMSA notes that the current ASME B31.4 code provides for a 7½ mile maximum valve spacing requirement on piping systems transporting liquefied petroleum gas or liquid anhydrous ammonia in industrial, commercial, and residential areas.

In an attempt to be more consistent with similar aspects of the natural gas pipeline regulations and taking into account the valve spacing requirements for Class 1 locations, PHMSA is proposing a 20-mile maximum valve spacing requirement for newly constructed and replaced hazardous liquid pipelines that could not affect HCAs.

Part 195 currently does not prescribe whether manual or remote control valves must be installed at particular locations, but it does require the consideration of check valves and remote control valves under the EFRD requirements for pipelines that could affect an HCA. Section 4 of the Act includes a new mandate for PHMSA to evaluate and issue additional regulations for the use of valves (such as remote control, automatic shut-off, or equivalent technology) for rupture mitigation. The current proposal seeks to establish a reasonable maximum distance that would apply to any type of terrain and in any area, regardless of population or environmental sensitivity. PHMSA expects that operators, in their pursuit of compliance with other valve location requirements, will locate, install, and equip valves for remote or automatic operation as needed and in accordance with the requirements of the integrity management regulations (§ 195.452(i)(4), including Appendix C). This will result in valve location profiles that meet their operational needs and are reflective of the risks and potential consequences unique to their individual pipelines, including the consideration of factors such as maximum spill volumes, terrain, and population and environmental

[36] *In the Matter of Viking Gas Transmission,* Final Order, C.P.F. No. 32102 (May 1, 1998).

[37] Valve spacing requirements are in the design and construction sections of the regulations. If a pipeline segment changes class location but can be successfully pressure tested to the MAOP standards of the next highest class location per § 192.611, PHMSA cannot retroactively impose new valve spacing on an existing segment. However, if the segment is replaced by virtue of a higher class location, the more stringent valve spacing requirements would apply.

receptors. The maximum spacing requirements would not supplant or supersede any other valve location requirement and would only apply to newly constructed and replaced pipelines of certain diameters. These proposed requirements address Section 4 of the 2011 Act and are consistent with PHMSA's efforts to address NTSB Recommendation P–11–11 for gas transmission pipelines as well.

For newly constructed and replaced segments that could affect an HCA or that are within an HCA, valves would be required at a minimum of every 15 miles. For new and replaced segments transporting highly volatile liquids (HVL) in HCAs established due to populated areas, the maximum distance between valves would be 7½ miles. This requirement mirrors the requirements that currently exist under ASME B31.4 for HVL mainline valve spacing and is necessary due to the unique safety risks these pipelines pose to populated areas. In addition, valves located on each side of a water crossing greater than or equal to 100 feet (30 meters) wide would be required to be installed outside the flood plain. The requirements of this proposed rule, specifically applying to segments of new or replaced pipelines that could potentially impact HCAs, would result in the placement of valves on each side of these HCA segments. This requirement acknowledges the sensitive nature of these specifically defined areas and requires their protection with mainline valves comparable to other sensitive locations.

The new requirements for valve spacing are proposed in §§ 192.179, 192.610 and 192.634 for gas transmission pipelines and §§ 195.260 and 195.418 for hazardous liquid pipelines.

E. Integrity Management and the Protection of HCAs

This NPRM would also strengthen integrity management requirements for both onshore gas transmission and hazardous liquid pipelines by addressing the use of ASVs or RCVs (including EFRDs) in HCAs as they apply to rupture mitigation. These existing requirements are at § 192.935(c) for gas transmission pipelines and § 195.452(i)(4) for hazardous liquid pipelines, and they specify that operators must conduct a risk analysis and add additional ASVs, RCVs, and EFRDs, as needed, to provide additional protections for HCAs. As gas transmission pipeline segments in HCAs are, by definition, near higher-population areas and developments and include areas where people assemble or have difficult-to-evacuate facilities such as schools or hospitals, releases from these segments have a higher potential for adverse consequences than releases from other segments.

i. Gas Transmission Pipelines

In the gas transmission ANPRM, commenters addressed PHMSA's consideration of additional decision criteria for operator evaluation of additional valves, remote closure, and valve automation. INGAA, AGA, GPTC, Ameren, and MidAmerican were not in support of additional decision criteria, whereas Accufacts, CPUC, and an anonymous commenter were in support of additional decision criteria. Accufacts argued that valve regulations should be required for larger-diameter gas transmission pipelines in HCAs, especially in areas where manual closure times could be long. CPUC expressed its conclusion that decision criteria may need to be added for all Method 1 HCA locations.[38]

PHMSA notes that although § 192.935 currently requires operators to consider installing additional RCVs and ASVs to mitigate potential consequences to HCAs, the regulation does not establish criteria based on consequence reduction to guide operator decisions. In developing this rulemaking, PHMSA has noted the challenges of requiring certain types of valves at specific locations. Therefore, PHMSA has determined that the most beneficial criteria for rupture mitigation are standards for rupture identification and response times paired with maximum valve spacing requirements, because limiting the consequences of a release is primarily dependent upon how quickly an operator identifies, acknowledges, and isolates a rupture. In this NPRM, the required time thresholds for operator response following rupture identification serve as the decision criteria. Because the rupture response and mitigation requirements of this rulemaking will apply to newly constructed systems and entirely replaced pipeline systems of 2 contiguous miles or greater, operators can design their valve configurations as needed to address site-specific issues while meeting the proposed rupture-mitigation requirements. Operators can determine what kinds of response and communication procedures need to be established, if arrangements need to be made for valve access by local operating personnel, if valves need to be equipped for remote or automatic operation and whether some other alternative equivalent technology can be employed to meet the standard.

ii. Hazardous Liquid Pipelines

The hazardous liquid integrity management regulations issued in 2002 require operators to assess and adjust their existing EFRD configurations to better protect HCAs. GAO's findings in GAO–13–168 support PHMSA's experience that large discrepancies still exist in how individual operators use existing valves as EFRDs, due largely to the lack of prescription in both the regulations and industry standards relating to EFRD installation. The lack of rapid closure capability has been found to have significantly exacerbated both the volume released and the adverse consequences in past accidents, even when emergency situations were quickly recognized by the operator. The ORNL report (ORNL/TM–2012/411) confirmed that ''swiftness of valve closure has a significant effect on mitigating potential socioeconomic and environmental damage to the human and natural environments.'' Similarly, the GAO study also found that ''quickly isolating the pipeline segment through automated valves can significantly reduce subsequent damage by reducing the amount of hazardous liquid released.''

PHMSA determined that there is a need to establish additional requirements related to EFRD actuation for newly constructed and replaced pipelines of 2 contiguous miles or greater in HCAs, as pairing standards for valve actuation with considerations for valve placement will help to achieve fuller safety benefits when considering rupture mitigation. This NPRM would also include annual inspection and maintenance requirements to assure that any valves installed under this rulemaking would reliably operate on-demand during emergency situations.

In response to the hazardous liquid ANPRM of October 18, 2010, PHMSA received comments on location and performance standards for EFRDs from industry and trade associations. API, AOPL, TxOGA, LMOGA, and TransCanada Keystone Pipeline reported that no industry standards currently address EFRD use. PHMSA also received several comments regarding location requirements for EFRDs, indicating that PHMSA should

[38] Method 1 is defined in § 192.903 HCA definition, paragraph (1) as a Class 3 or Class 4 location as those terms are defined under § 192.5; or any area within a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet, and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site. Definitions for ''potential impact radius,'' ''potential impact circle,'' and ''identified site'' are at § 192.903.

not specify the location of EFRDs. More specifically, API, AOPL, TransCanada Keystone Pipeline, LMOGA, and TxOGA indicated that a requirement to place EFRDs at predetermined locations or fixed intervals in lieu of a comprehensive engineering risk analysis would be arbitrary, costly, and potentially counter-productive to pipeline safety. They noted that § 195.452 already requires EFRDs to be installed to protect an HCA if the operator determines, through a risk assessment, that an EFRD is needed, and TPA suggested that no general criteria beyond those in the existing regulations are appropriate because decisions on EFRD placement are driven by local factors. Conversely, NSB and MAWUC stated EFRDs should be required on all pipelines PHMSA regulates, with specific instruction or criteria on when and where EFRDs need to be used, especially if they can limit a spill.

As discussed above, PHMSA determined that the lack of more comprehensive and specific guidance regarding the location and performance requirements for EFRDs perpetuates the inconsistencies and large variances in operators' response times in isolating pipeline segments when failures occur, particularly when a rupture or other fast-acting, large-volume release occurs. Valves, even when located properly, are more effective in failure scenarios when they can be closed quickly to isolate the failed segment. PHMSA also notes that ASME B31.4, ''Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids'' (2009), addresses mainline valves and specifies operators install RCVs and/or check valves in certain instances.

Furthermore, PHMSA determined that, although the EFRD evaluation requirement already exists for HCA segments, additional measures are needed to specifically address rupture mitigation for new and replaced pipelines. In accident reports submitted to PHMSA by operators from 2010 to 2017, just over one-half of all HCA incidents where valve type was recorded occurred at a location where either the upstream or downstream valve was an automatic, remotely controlled, or check valve. In approximately one-third of incidents occurring in an HCA, both the upstream and down valves were actuated by some manner of automation. It is difficult to envision a case where some type of rupture-mitigation valve (which in some cases can be an EFRD) on either side of (or within) an HCA segment would not provide additional protection. In all cases where a valve cannot be quickly accessed and manually closed, remote or automatic actuation is the only way to ensure prompt and effective closure.

In the hazardous liquid pipeline regulations, EFRDs are defined as check valves or remote-control valves. Although check valves can be considered as either an ASV or an EFRD in some applications, this NPRM only considers them to be a rupture-mitigation valve if an operator can demonstrate the valve's operational and protective equivalence when the valve is used for segment shut-off and isolation in response to a rupture. The NPRM proposes that operators must annually verify check valves or EFRDs are operational if they serve as rupture-mitigation valves. Considerations for the use of check valves as alternative equivalent technology for rupture mitigation should include all of the factors identified in this proposal and all existing regulations, including those contained in part 195, appendix C, such as the nature and characteristics of the transported commodity, the physical and operating characteristics of the pipeline, the hydraulic gradient of the pipeline, the terrain surrounding the pipeline, and all other factors pertinent to rupture mitigation including valve closure sealing performance and closure times.

F. Failure Investigations

Current pipeline safety regulations (§ 192.617 for gas transmission pipelines and § 195.402(c)(5) for hazardous liquid pipelines) require operators to report all incidents (gas) and accidents (hazardous liquid) over certain reporting thresholds, and to investigate incidents and accidents involving failed pipe, failed components or other pipeline system equipment, and incorrect operations. The terms incident and accident are used interchangeably in this NPRM.

In addition to the proposed rupture response and mitigation requirements, PHMSA is proposing new specific requirements for post-accident analysis (*i.e.,* an accident investigation) of any rupture or other event involving the activation of rupture-mitigation valves. These post-accident reviews would focus on ways to ensure that the proposed performance objectives in this NPRM are met in the future and that lessons learned can be applied by the operator system-wide. PHMSA has determined this will improve the safety performance of individual operators, while also improving the industry's overall safety performance through information sharing forums.

The NTSB noted in its accident report of the PG&E incident at San Bruno, CA, that many of the organizational deficiencies causing the incident were previously known to the operator as a result of previous accidents. The NTSB further noted that, as a lesson from those accidents, PG&E should have critically examined all components of its pipeline system to identify and analyze risks as well as update emergency response procedures. Had this recommended approach been taken by PG&E following earlier incidents, the NTSB argued, the San Bruno accident may have been prevented. Similar organizational failures were found following the Enbridge incident near Marshall, MI, and the NTSB noted that Enbridge failed to adapt lessons learned into its IM program.

Consistent with the findings in the GAO Report (GAO–13–168) and recommendations as described in this section, the proposed amendments in this NPRM would include new post-accident review and implementation requirements in §§ 192.617 and 195.402(c)(5). As provided in the regulatory text, PHMSA would expect operators would analyze data points including, but not limited to, the time taken to detect a rupture, the time taken to initiate mitigative actions, emergency response communications, personnel response time, valve closure time, SCADA performance, and valve location. Operators would then use these data points to enact improvements to the operator's suite of procedures, including its training and qualification programs, pipeline system design, risk management, operations and maintenance activities, and emergency response procedures.

IV. Section-by-Section Analysis of Changes to 49 CFR Part 192 for Gas Transmission Pipelines

Sec. 192.3 Definitions

Most of the requirements of this NPRM would be triggered by the identification of a ''rupture.'' Section 192.3 would be amended to define ''rupture'' as any of the following events that involve an uncontrolled release of a large volume of gas over a short period of time: (1) An unanticipated or unplanned pressure loss of 10 percent or more, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss a need for a higher pressure change; (2) an unexplained flow-rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event described above; or (3) an apparent large-volume, uncontrolled release of gas or a failure observed by operator personnel, the public, or public authorities, that is reported to the operator and that may be representative of an unintentional and uncontrolled release event that is defined in the items above.

Sec. 192.179 Transmission Line Valves

PHMSA proposes adding paragraph (e) to require that all valves on newly constructed or entirely replaced onshore gas transmission pipelines that have nominal diameters greater than or equal to 6 inches be automatic shut-off valves, remote-control valves, or an equivalent technology, unless such valves are not economically, technologically, or operationally feasible. PHMSA proposes to permit the installation of manual valves as rupture-mitigation valves only when there are feasibility issues precluding the installation of automatic or remote-control valves. All valves installed per this requirement would have to meet the new rupture-mitigation standards proposed in § 192.634 and isolate a ruptured pipeline segment within 40 minutes of rupture identification. Rupture identification would be defined in § 192.3 to occur when a rupture is reported to or observed by pipeline operating personnel or a controller.

Sec. 192.610 Change in Class Location: Change in Valve Spacing

A new § 192.610 is proposed to specify rupture-mitigation valve requirements when a class location changes. In cases where pipe is replaced to meet the maximum allowable operating pressure in accordance with requirements for class location changes under §§ 192.611, 192.619(a), and 192.620, then the rupture-mitigation valve installation requirement in § 192.179 applies for the new class location, which may require the operator to install new valves, and the rupture-mitigation requirements of § 192.634 would apply as well. Such additional valves must be installed within 24 months of the class location change.

Sec. 192.615 Emergency Plans

PHMSA proposes to revise paragraphs (a)(2), (a)(6), (a)(8), (a)(11), and (c) of § 192.615 to require that emergency procedures provide for rupture mitigation in response to a rupture event, including specific timing provisions relating to the identification of ruptures. Specifically, operators must have procedures in place allowing them to identify a rupture event within 10 minutes of the initial notification to the operator. PHMSA also proposes to require that operators maintain liaison with and contact the appropriate public safety answering point (9–1–1 emergency call center) in the event an operator's pipeline ruptures.

Sec. 192.617 Investigation of Failures and Incidents

PHMSA proposes to revise § 192.617 to define the elements that an operator must incorporate when conducting a post-incident analysis of certain specifically defined incidents, namely ruptures, and other release and failure events involving the activation of rupture-mitigation valves.

The proposed revision would require the operator to identify potential preventive and mitigative measures that could be taken to reduce or limit the release volume and damage from similar events in the future. The post-incident review would address factors associated with this rulemaking, including but not limited to detection and mitigation actions, response time, valve location, valve actuation, and SCADA performance. Upon completing the post-accident analysis, the operator must develop and implement the lessons learned throughout its suite of procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

Sec. 192.634 Transmission Lines: Onshore Valve Shut-Off for Rupture Mitigation

Proposed new § 192.634 would establish an emergency operations standard requiring operators to isolate certain ruptured pipeline segments as soon as practicable via rupture-mitigation valves with complete segment isolation as soon as practicable but within 40 minutes of identifying a rupture. This would apply to newly constructed and entirely replaced onshore gas transmission pipeline segments in HCAs and Class 3 and Class 4 locations with nominal diameters greater than or equal to 6 inches, and it would also apply to any gas transmission pipelines where 2 or more contiguous miles of pipeline with nominal diameters greater than or equal to 6 inches are replaced in HCAs and Class 3 and Class 4 locations. This NPRM would require that operators designate shut-off segments in these areas and designate mainline valves used to isolate ruptures on those shutoff segments as rupture-mitigation valves. This rulemaking would establish maximum distances between rupture-mitigation valves from 8 to 20 miles depending on the pipeline's class location. Compliance with the standard could be achieved using ASVs, RCVs, or an equivalent technology. Operators may install manually or locally operated valves to act as rupture-mitigation valves only if the installation of ASVs, RCVs, or equivalent technology is not feasible at the location, provided the operator demonstrates that the 40-minute closure standard can be achieved under emergency conditions. Operators using manual valves or other equivalent technology must notify PHMSA in accordance with the procedure outlined in § 192.634(h). The NPRM would also require that operators monitor the position and operational status of all rupture-mitigation valves. Operators will be required to meet these provisions within 12 months after the effective date of the final rule.

Sec. 192.745 Valve Maintenance: Transmission Lines

PHMSA proposes to revise § 192.745 by adding paragraphs (c), (d), and (e) to incorporate the maintenance, inspection, and operator drills required to ensure operators can close a rupture-mitigation valve as soon as practicable, but within 40 minutes of rupture identification. Demonstration and verification requirements are proposed, including point-to-point verification tests for rupture-mitigation valves that are ASVs or RCVs and initial validation drills and periodic confirmation drills for any manually or locally operated valve identified as a rupture-mitigation valve. The operator would be required to identify corrective actions and lessons learned resulting from its validation and confirmation drills and share and implement them across its entire network of pipeline systems.

Sec. 192.935 What additional preventive and mitigative measure must an operator take?

PHMSA proposes to revise § 192.935(c) to clarify the requirements for conducting ASV and RCV evaluations for HCAs, particularly when RCVs and ASVs are installed as preventive and mitigative measures associated with improved response times for pipeline ruptures. The amendments would require that operators be able to evaluate and demonstrate that they could identify a rupture within 10 minutes in accordance with the proposed § 192.615(a)(6) and meet the standard specified in the proposed § 192.634 to isolate shut-off segments in HCAs during rupture events as soon as practicable but within 40 minutes. Operators would also be required to demonstrate, through the risk analysis required by this section, that any ASVs or RCVs installed under this section can comply with the proposed valve maintenance requirements at § 192.745.

V. Section-by-Section Analysis for Changes to 49 CFR Part 195 for Hazardous Liquid Pipelines

Sec. 195.2 Definitions

Most of the requirements of the NPRM would be triggered by the identification of a ''rupture.'' Section 195.2 would be amended to define ''rupture'' for hazardous liquid pipelines as any of the following events that involve an uncontrolled release of a large volume of hazardous liquid over a short period of time: (1) An unanticipated or unplanned flow rate change of 10 percent or greater or a pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the flow rate change or pressure loss the need for a higher flow rate change or higher pressure-change threshold due to pipeline flow dynamics and terrain elevation changes that cause fluctuations in hazardous liquid flow that are typically higher than a flow rate change or pressure loss of 10 percent or greater in a time interval of 15 minutes or less; (2) An unexpected flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined above; or (3) An apparent large-volume, uncontrolled release of hazardous liquid or a failure observed by operator personnel, the public, or public authorities, that is reported to the operator and that may be representative of an unintentional and uncontrolled release event that is defined above.

Sec. 195.258 Valves: General

PHMSA proposes to require that all valves on newly constructed and entirely replaced hazardous liquid lines that have nominal diameters greater than or equal to 6 inches be RCVs, ASVs, or an equivalent technology, unless such valves are not economically, technologically, or operationally feasible. PHMSA proposes to permit operators install manually or locally operated valves only when there are feasibility issues precluding the installation of ASVs, RCVs, or equivalent technology. All valves installed under this requirement would have to meet the new rupture-mitigation standards proposed in § 195.418 and isolate a ruptured pipeline segment as soon as practicable, but within 40 minutes of rupture identification. Rupture identification would be defined in § 195.2 to occur when a rupture is reported to or observed by pipeline operating personnel or a controller.

Sec. 195.260 Valves: Location

Section 195.260 proposes the requirements for the location of valves on newly constructed hazardous liquid pipelines, entirely replaced hazardous liquid pipelines, and hazardous liquid pipelines where 2 or more contiguous miles have been replaced. PHMSA proposes to revise § 195.260 to incorporate new maximum valve spacing requirements for the general placement of valves, including a 20-mile maximum spacing requirement for valves on pipelines that could not affect high consequence areas, with more stringent maximum spacing requirements of 15 miles and 7.5 miles for pipelines that could affect HCAs and HVL pipelines in populated areas, respectively. These valve spacing requirements carry over to the rupture-mitigation valve spacing requirements at § 195.418 as well, where operators would be required to install rupture-mitigation valves at a maximum of every 15 miles but no further than 7½ miles from the HCA segment endpoints and at a maximum of every 7½ miles for HVL lines in highly populated areas. Revisions to § 195.260 would also include two miscellaneous clarifications: (1) To explicitly include carbon dioxide as a transported commodity whose consequences are to be considered, and (2) to include new requirements pertaining to valves at water crossings to ensure these valves will not be impacted by flood conditions and to allow multiple water crossings to be protected by a single pair of valves.

Sec. 195.402 Procedural Manual for Operations, Maintenance, and Emergencies

PHMSA proposes to revise § 195.402 to identify the areas requiring an immediate response by the operator to prevent hazards to the public, property, or the environment if the facilities failed or malfunctioned, including segments that could affect HCAs and segments with valves that are specified in §§ 195.418 and 195.452(i)(4).

PHMSA is also revising § 195.402 to define the elements that an operator must incorporate when conducting a post-accident analysis of ruptures and other release and failure events involving the activation of rupture-mitigation valves. The proposed revision would require the operator to identify potential preventative and mitigative measures that could be taken to reduce or limit the release volume and damage from similar events in the future. The post-accident review would address factors associated with this rulemaking, including but not limited to detection and mitigation actions, response time, valve location, valve actuation, and SCADA performance. Upon completion of this post-accident analysis, the operator would be required to develop and implement the lessons learned throughout its suite of procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

Further, PHMSA is revising § 195.402 to clarify that requirements to establish liaison with emergency officials must include public safety answering points (9–1–1 emergency call centers) and that requirements for notifying emergency officials when events occur must include notifications to those local public safety answering points.

Section 195.402 also require that emergency procedures provide for rupture detection and valve closure in response to a leakage or failure event, including specific timing provisions relating to ruptures. Specifically, operators must have procedures in place so that they can identify a rupture event within 10 minutes of the initial notification to the operator. This section would also be revised as a matter of minor clarification to incorporate valve shut-off as an example of an emergency action to minimize the hazards of released hazardous liquid or carbon dioxide to life, property, or the environment.

Sec. 195.418 Valves: Onshore Valve Shut-Off for Rupture Mitigation

Proposed new § 195.418 would establish an emergency operations standard requiring operators to isolate certain ruptured pipeline segments as soon as practicable via rupture-mitigation valves with complete segment isolation within 40 minutes of identifying a rupture. This standard would apply to newly constructed and entirely replaced onshore hazardous liquid pipelines in HCAs and that could affect HCAs with nominal diameters greater than or equal to 6 inches, and it would also apply to any hazardous liquid pipelines where 2 or more contiguous miles of pipeline with nominal diameters greater than or equal to 6 inches are replaced in HCAs or where they could affect HCAs. This NPRM would require that operators designate shut-off segments in these areas and designate mainline valves used to isolate ruptures on those shut-off segments as rupture-mitigation valves. This NPRM would establish maximum distances of 15 miles between rupture-mitigation valves and 7½ miles between rupture-mitigation valves on HVL lines, which are consistent with the proposed spacing requirements of § 195.260. Operators could use ASVs, RCVs, an equivalent technology, or manually operated valves (if the operator demonstrates infeasibility of ASVs, RCVs and equivalent technology, that the standard can be achieved under emergency conditions, and provides notification to PHMSA). Operators would also be required to monitor the position and operational status of all rupture-mitigation valves. Operators will be required to meet these provisions within 12 months after the effective date of the final rule.

Sec. 195.420 Valve Maintenance

PHMSA proposes to revise § 195.420 to incorporate the maintenance, inspection, and operator drills required to ensure operators can close a rupture-mitigation valve as soon as practicable but within 40 minutes. Demonstration and verification requirements are proposed, including point-to-point verification tests for rupture-mitigation valves that are ASVs or RCVs and initial validation drills and periodic confirmation drills for any manually or locally operated valves identified as rupture-mitigation valves. This section would also require an operator to identify corrective actions and lessons learned resulting from its validation or confirmation drills and share and implement those lessons learned across its entire network of pipeline systems.

Sec. 195.452 Pipeline Integrity Management in High Consequence Areas

PHMSA proposes to revise § 195.452(i)(4) to clarify the existing requirements for the conduct of EFRD evaluations for HCAs, particularly when operators use EFRDs as rupture-mitigation valves on applicable lines. Further, the amendments would also require that operators be able to evaluate and demonstrate that they could identify a rupture within 10 minutes in accordance with the proposed § 195.402 and meet the standard specified in the proposed § 195.418 to isolate shut-off segments that could affect HCAs during rupture events, and the amendments would require that any EFRDs installed on shut-off segments also comply with the design, operation, testing, and maintenance requirements of §§ 195.258, 195.260, 195.402, and 195.420.

VI. Regulatory Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This NPRM is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The Secretary delegated this authority to PHMSA at 49 CFR 1.97(a).

B. Executive Orders 12866 and 13771, and DOT Regulatory Policies and Procedures

Executive Order 12866 requires agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' This NPRM has been determined to be significant under Executive Order 12866 and the Department of Transportation's Regulatory Policies and Procedures. This NPRM has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 (Regulatory Planning and Review) and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)–(6).

Consistent with Executive Order 12866, PHMSA has prepared a preliminary assessment of the benefits and costs of the proposed rule as well as reasonable alternatives. PHMSA anticipates that, if promulgated, this NPRM will provide benefits to the public through more rapid valve closure resulting in better consequence mitigation.

For hazardous liquid pipelines, most damages are calculated by the cost of cleanup and long-term environmental remediation.[39] Therefore, a reduction in the amount of product released from a hazardous liquid pipeline can directly correlate to a reduction in damages. As discussed earlier in this NPRM, in the Enbridge incident near Marshall, MI, the pipeline continued to pump oil for 18 hours before valves were closed, resulting in approximately 20,000 barrels of oil being released. With faster rupture detection, pump shutdowns, and valve closures in line with this NPRM, the pipeline would have been isolated 17 hours and 20 minutes earlier, which would have resulted in a substantially lower spill size, environmental impact, and remedial costs.

Natural gas transmission pipeline incidents result predominately in fatalities, injuries, or property damages that are not linearly related to the quantity of natural gas released. For small incidents and for those incidents in remote locations, damages may be limited to pipeline repair and gas loss costs. Larger incidents, on the other hand, likely involve the ignition of gas and extensive property damage and personal injury, depending on the location of the release and its proximity to buildings, homes, or other areas. A reduction in the cumulative product release over these types of incidents would not necessarily imply avoided damages in the way that it would apply to hazardous liquid pipelines as discussed above. For example, in the PG&E incident, the homes destroyed by the initial rupture would not have been saved through a more prompt valve closure. However, as discussed earlier in this document, during the 95 minutes it took PG&E to isolate the ruptured segment, the fire resulting from the rupture was being fed by the transmission line, and firefighters could not start firefighting and containment activities until the line was isolated. Earlier valve closure, in that circumstance, could have limited the spread of fire and additional damage beyond the immediate rupture area.

PHMSA estimates that the NPRM will result in annualized costs of approximately $3.1 million per year, calculated at a 7 percent discount rate. The table below presents the annualized costs for the baseline and this NPRM, at a 3 percent and a 7 percent discount rate:

TABLE 1—ANNUALIZED COSTS OF THE PROPOSED RULE

[Millions 2015$]

System type	7% Discount rate	3% Discount rate
Gas transmission	$1.2	$1.0
Hazardous liquid	1.9	1.5
Total	3.1	2.5

The NPRM is expected to be an E.O. 13771 regulatory action. Details on the estimated costs of this NPRM can be found in the rule's economic analysis.

For more information, please see the PRIA in the docket for this rulemaking.

[39] PHMSA notes that HVL releases may have similar incident profiles to natural gas transmission pipelines, as escaping product can be ignited and cause similar damage via a rupture.

C. Executive Order 13132: Federalism

PHMSA has analyzed this rulemaking action according to Executive Order 13132 (''Federalism''). While this NPRM may preempt some State requirements, it does not impose any regulation that has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibit State safety regulation of interstate pipelines. Under the pipeline safety laws, States have the ability to augment pipeline safety requirements for intrastate pipelines, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare an Initial Regulatory Flexibility Analysis (IRFA) for any proposed rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rulemaking will not have a significant economic impact on a substantial number of small entities.

PHMSA prepared an IRFA of the potential economic impact on small entities, which is available in the docket for this NPRM. For a worst-case scenario, PHMSA compared compliance costs to estimated sales for businesses. Average annualized costs could exceed 1 percent of sales for 34 (8 percent) of the estimated small gas transmission entities and 12 (19 percent) of the estimated small hazardous liquid operators for a total of 46 (10 percent) entities combined across both sectors. Average annualized costs could exceed 3% of sales for 3 (1 percent) gas transmission operators and 4 (6 percent) hazardous liquid operators, which represent 7 (1 percent) of the total estimated small business entities.

Due to various uncertainties in the screening analysis (see Table 7 in the IRFA), PHMSA seeks comments regarding the impacts of the NPRM on small entities. PHMSA will subsequently modify the IRFA and make a determination as to whether this NPRM will have a significant economic impact on a number of small entities at the final rule stage.

E. National Environmental Policy Act

PHMSA analyzed this NPRM in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT Order 5610.1C, and has preliminarily determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this NPRM is in the docket.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA has analyzed this NPRM in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments''). Because this NPRM is not expected to have Tribal implications and is not expected to impose substantial direct compliance costs on Indian Tribal governments, PHMSA does not anticipate that the funding and consultation requirements of Executive Order 13175 will apply. PHMSA seeks comment on the applicability of the executive order to this NPRM.

G. Executive Order 13211

This NPRM is not anticipated to be a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this proposed rule as a significant energy action.

H. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA estimates that the proposals in this NPRM will create the following Paperwork Reduction Act impacts:

PHMSA proposes to create a new information collection to cover the recordkeeping requirement for post-incident recordkeeping called: ''Rupture/Shut-off Valve: Post-Incident Records for Pipeline Operators.'' PHMSA also proposes to create a new information collection called ''Alternative Technology for Onshore Rupture Mitigation Notifications'' to cover this specific notification requirement.

PHMSA will submit information collection requests to the Office of Management and Budget (OMB) for approval based on the requirements that trigger components of the Paperwork Reduction Act in this NPRM. PHMSA will also request two new OMB Control Numbers for these collections. These information collections are contained in the pipeline safety regulations, 49 CFR parts 190–199. The following information is provided for each of these information collections: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burdens are estimated as follows:

1. Title: ''Rupture/Valve Shut-off: Post-Incident Records for Pipeline Operators.''

OMB Control Number: Will request one from OMB.

Current Expiration Date: New Collection—To be determined.

Abstract: This NPRM proposes to amend 49 CFR 192.617 and 195.402 to require operators who have experienced a rupture or rupture-mitigation valve shut-off to complete a post-incident summary. The post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the life of the pipeline. PHMSA estimates this recordkeeping requirement will result in 50 responses annually and has allotted each respondent 8 hours per response to make and maintain the required records. PHMSA does not currently have an information collection that covers this requirement and will request the approval of this new collection, along with a new OMB Control Number, from the Office of Management and Budget.

Affected Public: Operators of PHMSA-regulated pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 50.

Total Annual Burden Hours: 400.

Frequency of Collection: On occasion.

2. Title: ''Alternative Equivalent Technology for Onshore Rupture Mitigation Notifications.''

OMB Control Number: Will request one from OMB.

Current Expiration Date: New Collection—To be determined.

Abstract: This NPRM proposes a new paragraph (d) in both 49 CFR 192.634 and 195.418 requiring operators who elect to use alternative equivalent technology to notify, in accordance with 192.949, the Office of Pipeline Safety at least 90 days in advance of use. An operator choosing this option must include a technical and safety evaluation, including design, construction, and operating procedures for the alternative equivalent technology to the Associate Administrator of Pipeline Safety with the notification. PHMSA would then have 90 days to object to the alternative equivalent technology via letter from the Associate Administrator of Pipeline Safety; otherwise, the alternative equivalent technology would be acceptable for use. PHMSA estimates this notification requirement will result in 2 responses annually and has allotted each respondent 40 hours per response to conduct this task. PHMSA does not currently have an information collection that covers this requirement and will request the approval of this new collection, along with a new OMB Control Number, from the Office of Management and Budget.

Affected Public: Operators of PHMSA-regulated pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2.

Total Annual Burden Hours: 80.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration, 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone: 202–366–1246.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

(e) Ways the collection of this information is beneficial or not beneficial to public safety.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to April 6, 2020.

I. Unfunded Mandates Reform Act of 1995

The analysis PHMSA performed in accordance with preparing the Preliminary Regulatory Impact Assessment does not expect this NPRM to impose unfunded mandates per the Unfunded Mandates Reform Act of 1995. It is not expected to result in costs of $100 million, adjusted for inflation, or more in any one (1) year to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the proposed rulemaking. A copy of the Preliminary Regulatory Impact Assessment is available for review in the docket.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: *https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf.*

K. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN contained in the heading of this document may be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 192

Gas, Incorporation by reference, Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 195

Anhydrous ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 192 and 195 as follows:

PART 192—TRANSPORTATION OF NATURAL GAS AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et. seq., and 49 CFR 1.97.

■ 2. In § 192.3, the definition of "rupture" is added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Rupture means any of the following events that involve an uncontrolled release of a large volume of gas:

(1) A release of gas observed or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition;

(2) An unanticipated or unplanned pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less; or

(3) An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined in paragraph (2) of this definition.

Note: Rupture identification occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

* * * * *

■ 3. In § 192.179, paragraph (e) is added to read as follows:

§ 192.179 Transmission line valves.

* * * * *

(e) All onshore transmission line segments with diameters greater than or equal to 6 inches that are constructed or entirely replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] must have automatic shutoff valves, remote-control valves, or equivalent technology installed at intervals meeting the appropriate valve spacing requirements of this section. An operator may only install a manual valve under this paragraph if it can demonstrate to PHMSA that installing an automatic shutoff valve, remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator using alternative equivalent technology or manual valve must notify PHMSA in accordance with the procedure in § 192.634(h). All valves and technology installed under this paragraph must meet the requirements of § 192.634(c), (d), (f), and (g).

■ 4. Section 192.610 is added to read as follows:

§ 192.610 Change in class location: Change in valve spacing.

If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement to meet the maximum allowable operating pressure requirements in §§ 192.611, 192.619, or 192.620, then the requirements in §§ 192.179 and 192.634 apply to the new class location, and the operator must install valves as necessary to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with § 192.611(d).

■ 5. In § 192.615, paragraphs (a)(2), (6), (8), and (11), and paragraph (c) introductory text are revised to read as follows:

§ 192.615 Emergency plans.

(a) * * *

(2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency, and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication.

* * * * *

(6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system to minimize hazards of released gas to life, property, or the environment. Each operator installing valves in accordance with § 192.179(e) or subject to the requirements in § 192.634 must also evaluate and identify a rupture as defined in § 192.3 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable but within 10 minutes of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

* * * * *

(8) Notifying the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency. The operator (pipeline controller or the appropriate operator emergency response coordinator) must immediately and directly notify the appropriate public safety answering point (9–1–1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and rupture-mitigation valve closure is implemented.

* * * * *

(11) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and §§ 192.631 and 192.634.

* * * * *

(c) Each operator must establish and maintain liaison with the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials to:

* * * * *

■ 6. Section 192.617 is revised to read as follows:

§ 192.617 Investigation of failures and incidents.

(a) *Post-incident procedures.* Each operator must establish and follow post-incident procedures for investigating and analyzing failures and incidents as defined in § 191.3, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, to determine the causes and contributing factors of the failure or incident and minimize the possibility of a recurrence.

(b) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-incident review into its procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

(c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or incident involves a rupture as defined in § 192.3 or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must also conduct a post-incident analysis of all factors impacting the release volume and the consequences of the release, and identify and implement preventive and mitigative measures to reduce or limit the release volume and damage in a future failure or incident. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:

(1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release or failure event;

(2) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;

(3) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;

(4) Location and the timeliness of actuation of rupture-mitigation valves identified under § 192.634; and

(5) All other factors the operator deems appropriate.

(d) *Rupture post-incident summary.* If a failure or incident involves a rupture as defined in § 192.3 or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must complete a summary of the post-incident review required by paragraph (c) of this section within 90 days of the failure or incident, and while the investigation is pending, conduct quarterly status reviews until completed. The post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the appropriate senior executive officer. The post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline.

■ 7. Section 192.634 is added to read as follows:

§ 192.634 Transmission lines: Onshore valve shut-off for rupture mitigation.

(a) *Applicability.* For onshore transmission pipeline segments with nominal diameters of 6 inches or greater in high consequence areas or Class 3 or Class 4 locations that are constructed or where 2 or more contiguous miles have been replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], an operator must install rupture-mitigation valves according to the requirements of this section. Rupture-mitigation valves must be operational within 7 days of placing the new or replaced pipeline segment in service.

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

(1) *High Consequence Areas.* For purposes of this paragraph (b)(1), ''shut-off segment'' means the segment of pipe located between the upstream mainline valve closest to the upstream high consequence area segment endpoint and the downstream mainline valve closest to the downstream high consequence area segment endpoint so that the entirety of the high consequence area segment is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, then the segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). All such valves on a shut-off segment are ''rupture-mitigation valves.'' Multiple high consequence areas may be contained within a single shut-off segment. The distance between rupture-mitigation valves for each shut-off segment must not exceed:

(i) 8 miles if one or more high consequence areas in the shutoff segment is in a Class 4 location;

(ii) 15 miles if one or more high consequence areas in the shutoff segment is in a Class 3 location, and

(iii) 20 miles if all high consequence areas in the shutoff segment are located in Class 1 or 2 locations, or

(iv) The mainline valve spacing requirements of § 192.179 when mainline valve spacing does not meet § 192.634(b)(1)(i), (ii), or (iii).

(2) *Class 3 locations.* For purposes of this paragraph, ''shut-off segment'' means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the Class 3 location and the downstream mainline valve closest to the downstream endpoint of the Class 3 location so that the entirety of the Class 3 location is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). All such valves on a shut-off segment are ''rupture-mitigation valves.'' Multiple Class 3 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment must not exceed 15 miles.

(3) *Class 4 locations.* For purposes of this paragraph, ''shut-off segment'' means the segment of pipe between the upstream mainline valve closest to the upstream endpoint of the Class 4 location and the downstream mainline valve closest to the downstream endpoint of the Class 4 location so that the entirety of the Class 4 location is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). All such valves on a shut-off segment are ''rupture-mitigation valves.'' Multiple Class 4 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment must not exceed 8 miles.

(4) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have rupture-mitigation valves that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume, based upon maximum flow volume at the operating pressure.

(c) *Valve shut-off time for rupture mitigation.* Upon identifying a rupture, the operator must, as soon as practicable:

(1) Commence shut-off of the rupture-mitigation valve or valves which would have the greatest effect on minimizing the release volume and other potential safety and environmental consequences of the discharge to achieve full rupture-mitigation valve shut-off within 40 minutes of rupture identification; and

(2) Initiate other mitigative actions appropriate for the situation to minimize the release volume and potential adverse consequences.

(d) *Valve shut-off capability.* Onshore transmission line rupture-mitigation valves must have actuation capability (*i.e.,* remote-control shut-off, automatic shut-off, equivalent technology, or manual shut-off where personnel are in proximity) to ensure pipeline ruptures are promptly mitigated based upon maximum valve shut-off times, location, and spacing specified in paragraphs (b) and (c) of this section to mitigate the volume and consequence of gas released.

(e) *Valve shut-off methods.* All onshore transmission line rupture-mitigation valves must be actuated by one of the following methods to mitigate a rupture as soon as practicable but within 40 minutes of rupture identification:

(1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off following identification of a rupture or other decision to close the valve;

(2) Automatic shut-off following identification of a rupture; or

(3) Alternative equivalent technology that is capable of mitigating a rupture in accordance with this section.

(4) Manual operation upon identification of a rupture. Operators using a manual valve in accordance with § 192.179(e), must appropriately station personnel to ensure valve shut-off in accordance with paragraph (c) of this section. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to manually shut off all valves, not to exceed the 40-minute total response time in paragraph (c)(1) of this section.

(f) *Valve monitoring and operation capabilities.* Onshore transmission line rupture-mitigation valves actuated by methods in paragraph (e) of this section must be capable of being:

(1) Monitored or controlled by either remote or onsite personnel;

(2) Operated during normal, abnormal, and emergency operating conditions;

(3) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use manual valve operation must have the capability to monitor pressures and gas flow rates on the pipeline to be able to identify and locate a rupture;

(4) Initiated to close as soon as practicable after identifying a rupture and with complete valve shut-off within

40 minutes of rupture identification as specified in paragraph (c) of this section; and

(5) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.

(g) *Monitoring of valve shut-off response status.* Operating control personnel must continually monitor rupture-mitigation valve position and operational status of all rupture-mitigation valves for the affected shut-off segment during and after a rupture event until the pipeline segment is isolated. Such monitoring must be maintained through continual electronic communications with remote instrumentation or through continual verbal communication with onsite personnel stationed at each rupture-mitigation valve, via telephone, radio, or equivalent means.

(h) *Alternative equivalent technology or manual valves for onshore transmission rupture mitigation.* If an operator elects to use alternative equivalent technology or manual valves in accordance with § 192.179(e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.949. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valves 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valves or that PHMSA requires additional time to conduct its review.

■ 8. In § 192.745 paragraphs (c), (d), and (e) are added to read as follows:

§ 192.745 Valve maintenance: Transmission lines.

* * * * *

(c) For each valve installed under § 192.179(e) and each rupture-mitigation valve under § 192.634 that is a remote control shut-off or automatic shut-off valve, or that is based on alternative equivalent technology, the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 192.631(c) and (e).

(d) For each rupture-mitigation valve under § 192.634 that is manually or locally operated:

(1) Operators must establish the 40-minute total response time as required by § 192.634 through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. Each phase of the drill response must be reviewed and the results documented to validate the total response time, including valve shut-off, as being less than or equal to 40 minutes following rupture identification.

(2) A mainline valve serving as a rupture-mitigation valve within each pipeline system and within each operating or maintenance field work unit must be randomly selected for an annual 40-minute total response time validation drill that simulates worst-case conditions for that location to ensure compliance. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months.

(3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 192.634 no later than 6 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.

(4) Based on the results of response-time drills, the operator must include lessons learned in:

(i) Training and qualifications programs; and

(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and

(iii) Any other areas identified by the operator as needing improvement.

(e) Each operator must take remedial measures to correct any valve installed under § 192.179(e) or any rupture-mitigation valve identified in § 192.634 that is found to be inoperable or unable to maintain shut-off, as follows:

(1) Repair or replace the valve as soon as practicable but no later than 6 months after finding that the valve is inoperable or unable to maintain shut-off; and

(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made.

■ 9. In § 192.935, paragraph (c) is revised to read as follows:

§ 192.935 What additional preventive and mitigative measures must an operator take?

* * * * *

(c) Risk analysis for gas releases and protection against ruptures. If an operator determines, based on a risk analysis, that an automatic shut-off valve (ASV) or remote-control valve (RCV) would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(1) *Protection of onshore transmission high consequence areas from ruptures.* An operator of an onshore transmission pipeline segment that is constructed, or that has 2 or more contiguous miles replaced, after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] and is greater than or equal to 6 inches in nominal diameter and is located in a high consequence area must provide for the additional protection of those pipeline segments to assure the timely termination and mitigation of rupture events by complying with §§ 192.615(a)(6), 192.634, and 192.745. At a minimum, the analysis specified in paragraph (c) of this section must demonstrate that the operator can achieve the following standards for termination of rupture events:

(i) Operators must identify a rupture event as soon as practicable but within 10 minutes of the initial notification to or by the operator, in accordance with § 192.615(a)(6), regardless of how the rupture is initially detected or observed;

(ii) Operators must begin closing shut-off segment rupture-mitigation valves as soon as practicable after identifying a rupture in accordance with § 192.634; and

(iii) Operators must achieve complete segment shut-off and isolation as soon as practicable after rupture detection but within 40 minutes of rupture identification in accordance with § 192.634.

(2) *Compliance deadlines.* The risk analysis and assessments specified in paragraph (c) of this section must be completed prior to placing into service onshore transmission pipelines constructed or where 2 or more contiguous miles have been replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]. Implementation of risk analysis and assessment findings for rupture-mitigation valves must meet § 192.634.

(3) *Periodic evaluations.* Risk analyses and assessments conducted under

paragraph (c) of this section must be reviewed by the operator for new or existing operational and integrity matters that would affect rupture mitigation on an annual basis, not to exceed a period of 15 months, or within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively, and certified by the signature of a senior executive of the company.

* * * * *

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 10. The authority citation for part 195 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 11. In § 195.2, the definition for ''rupture'' is added in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Rupture means any of the following events that involve an uncontrolled release of a large volume of hazardous liquid or carbon dioxide:

(1) A release of hazardous liquid or carbon dioxide observed and reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition;

(2) An unanticipated or unplanned flow rate change of 10 percent or greater or a pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the flow rate change or pressure loss the need for a higher flow rate change or higher pressure-change threshold due to pipeline flow dynamics and terrain elevation changes that cause fluctuations in hazardous liquid or carbon dioxide flow that are typically higher than a flow rate change or pressure loss of 10 percent in a time interval of 15 minutes or less; or

(3) An unexplained flow rate change, pressure change, instrumentation indication or equipment function that may be representative of an event defined in paragraph (2) of this definition.

Note: Rupture identification occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

* * * * *

■ 12. In § 195.258, paragraph (c) is added to read as follows:

§ 195.258 Valves: General.

* * * * *

(c) All onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that are constructed or entirely replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] must have automatic shutoff valves, remote-control valves, or equivalent technology installed at intervals meeting the appropriate valve location and spacing requirements of this section and § 195.260. An operator may only install a manual valve under this paragraph if it can demonstrate to PHMSA that installing an automatic shutoff valve, remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator installing alternative equivalent technology or manual valves must notify PHMSA in accordance with the procedure at § 195.418(h). Valves and technology installed under this section must meet the requirements of § 195.418(c), (d), (f), and (g).

■ 13. In § 195.260, paragraphs (c) and (e) are revised and paragraphs (g) and (h) are added to read as follows:

§ 195.260 Valves: Location.

* * * * *

(c) On each mainline at locations along the pipeline system that will minimize or prevent safety risks, property damage, or environmental harm from accidental hazardous liquid or carbon dioxide discharges, as appropriate for onshore areas, offshore areas, or high consequence areas. For onshore pipelines constructed or that have had 2 or more contiguous miles replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], mainline valve spacing must not exceed 15 miles for pipeline segments that could affect high consequence areas (as defined in § 195.450) and 20 miles for pipeline segments that could not affect high consequence areas. Valves protecting high consequence areas must be located as determined by the operator's process for identifying preventive and mitigative measures established in § 195.452(i) and by using a process, such as is set forth in Section I.B of Appendix C of part 195, but with a maximum distance from the high consequence area segment endpoints that does not exceed 7½ miles.

* * * * *

(e) On each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark as follows, unless the Associate Administrator finds under paragraph (e)(3) of this section that valves or valve spacing is not necessary in a particular case to achieve an equivalent level of safety:

(1) Valves must either be located outside of the flood plain or have valve actuators and other control equipment installed to not be impacted by flood conditions; and

(2) For multiple water crossings, valves must be located on the pipeline upstream and downstream of the first and last water crossings so that the total distance between the first upstream valve and last downstream valve does not exceed 1 mile.

(3) An operator may notify PHMSA in accordance with paragraph (h) of this section if in a particular case the valves or valve spacing required by this paragraph is not necessary to achieve an equivalent level of safety. Unless the Associate Administrator finds in that particular case the valves or valve spacing required by this paragraph are not necessary to achieve an equivalent level of safety, the operator must comply with the valve and valve spacing requirements of this paragraph.

* * * * *

(g) On each mainline highly volatile liquid (HVL) pipeline that is located in a high population area or other populated area as defined in § 195.450 and that is constructed or that has 2 or more contiguous miles replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], with a maximum valve spacing of 7½ miles, unless the Associate Administrator finds in a particular case that this valve spacing is not necessary to achieve an equivalent level of safety. An operator may notify PHMSA in accordance with paragraph (h) of this section if in a particular case the valve spacing required by this paragraph is not necessary to achieve an equivalent level of safety. If the Associate Administrator informs an operator that PHMSA objects, the operator must comply with the valve spacing requirements of this paragraph.

(h) An operator must provide any notification required by this section by:

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

■ 14. In § 195.402, paragraphs (c)(4), (5), and (12), and (e)(1), (4), (7), and (10) are revised to read as follows:

§ 195.40 2 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(4) Determining which pipeline facilities are in areas that would require an immediate response by the operator to prevent hazards to the public, property, or the environment if the facilities failed or malfunctioned, including segments that could affect high consequence areas and valves specified in either §§ 195.418 or 195.452(i)(4).

(5) Investigating and analyzing pipeline accidents and failures, including sending the failed pipe, component, or equipment for laboratory testing or examination where appropriate, to determine the causes and contributing factors of the failure and minimize the possibility of a recurrence.

(i) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-accident review into its procedures, including in pertinent operator personnel training and qualifications programs and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

(ii) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or accident involves a rupture as defined in § 195.2 or a rupture-mitigation valve closure as defined in § 195.418, the operator must also conduct a post-accident analysis of all factors impacting the release volume and the consequences of the release, and identify and implement preventive and mitigative measures to reduce or limit the release volume and damage in a future failure or incident. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:

(A) Detection, identification, operational response, system shut-off, and emergency-response communications, based on the type and volume of the release or failure event;

(B) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;

(C) Actual response time from rupture identification to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;

(D) Location and the timeliness of actuation of all rupture-mitigation valves identified under § 195.418; and

(E) All other factors the operator deems appropriate.

(iii) *Rupture post-incident summary.* If a failure or incident involves a rupture as defined in § 195.2 or the closure of a rupture-mitigation valve as defined in § 195.418, the operator must complete a summary of the post-accident review required by paragraph (c)(5)(ii) of this section within 90 days of the failure or incident, and while the investigation is pending, conduct quarterly status reviews until completed. The post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the appropriate senior executive officer. The post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline.

* * * * *

(12) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency, and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication.

* * * * *

(e) * * *

(1) Receiving, identifying, and classifying notices of events that need immediate response by the operator or notice to the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other appropriate public officials, and communicating this information to appropriate operator personnel for corrective action.

* * * * *

(4) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment. Each operator installing valves in accordance with § 195.258(c) or subject to the requirements in § 195.418 must also evaluate and identify a rupture as defined in § 195.2 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable but within 10 minutes of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

* * * * *

(7) Notifying the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials, of hazardous liquid or carbon dioxide pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency, and any additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid. The operator (pipeline controller or the appropriate operator emergency response coordinator) must immediately and directly notify the appropriate public safety answering point (9–1–1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and valve closure is implemented.

* * * * *

(10) Actions required to be taken by a controller during an emergency, in accordance with the operator's emergency plans and §§ 195.418 and 195.446.

* * * * *

■ 15. Section 195.418 is added to read as follows:

§ 195.418 Valves: Onshore valve shut-off for rupture mitigation.

(a) *Applicability.* For onshore pipeline segments that could affect high consequence areas with nominal diameters of 6 inches or greater, that are constructed or where 2 or more contiguous miles are replaced after [DATE 12 MONTHS AFTER THE EFFECTIVE DATE OF THE RULE], an operator must install rupture-mitigation valves according to the requirements of this section and § 195.260. Rupture-mitigation valves must be operational within 7 days of placing the new or replaced pipeline segment in service.

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

(1) For purposes of this section, a ''shut-off segment'' means the segment of pipe located between the upstream mainline valve closest to the upstream high consequence area segment endpoint and the downstream mainline valve closest to the downstream high consequence area segment endpoint so that the entirety of the segment that could affect the high consequence area

is between at least two rupture-mitigation valves. If any crossover or lateral pipe for commodity receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for commodity to be transported to the rupture site (except for residual liquids already in the shut-off segment). All such valves on a shut-off segment are ''rupture-mitigation valves.'' Multiple high consequence areas may be contained within a single shut-off segment. All replacement pipeline segments that are over 2 continuous miles in length and could affect a high consequence area must include a minimum of one mainline valve that meets the requirements of this section. The distance between rupture-mitigation valves in high consequence areas for each shut-off segment must not exceed 15 miles, with a maximum distance not to exceed 7½ miles from the endpoints of a shut-off segment. Valves on lines carrying highly volatile liquids in high population areas and other populated areas, as those terms are defined in § 195.450, must have rupture-mitigation valves spaced at a maximum distance not exceeding 7½ miles.

(2) Lateral lines to shut-off segments that contribute less than 5 percent of the total shut-off segment commodity volume may have lateral rupture-mitigation valves that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these laterals contributing hazardous liquid or carbon dioxide volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment commodity volume based upon maximum flow gradients and terrain.

(c) *Valve shut-off time for rupture mitigation.* Upon identifying a rupture, the operator must, as soon as practicable:

(1) Commence shut-off of the rupture-mitigation valve or valves that would have the greatest effect on minimizing the release volume and other potential safety and environmental consequences of the discharge to achieve full rupture-mitigation valve shut-off within 40 minutes of rupture identification; and

(2) Initiate other mitigative actions appropriate for the situation to minimize the release volume and potential adverse consequences.

(d) *Valve shut-off capability.* Onshore rupture-mitigation valves must have actuation capability (*i.e.,* remote control shut-off, automatic shut-off, equivalent technology, or manual shut-off where personnel are in proximity) to ensure pipeline ruptures are promptly mitigated based upon maximum valve shut-off times, location, and spacing specified in paragraphs (b) and (c) of this section to mitigate the volume and consequence of hazardous liquid or carbon dioxide released.

(e) *Valve shut-off methods.* All onshore rupture-mitigation valves must be actuated by one of the following methods to mitigate a rupture as soon as practicable but within 40 minutes of rupture identification:

(1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off following identification of a rupture or other decision to close the valve;

(2) Automatic shut-off following an identification of a rupture; or

(3) Alternative equivalent technology that is capable of mitigating a rupture in accordance with this section.

(4) Manual operation upon identification of a rupture. Operators using a manual valve in accordance with § 195.258 must appropriately station personnel to ensure valve shut-off in accordance with paragraph (c) of this section. Manual operation of valves must include time for the assembly of necessary operating personnel, acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to manually shut off all valves, not to exceed a 40-minute total response time in paragraph (c)(1) of this section.

(f) *Valve monitoring and operation capabilities.* Onshore rupture-mitigation valves actuated by methods in paragraph (e) of this section must be capable of being:

(1) Monitored or controlled by either remote or onsite personnel;

(2) Operated during normal, abnormal, and emergency operating conditions;

(3) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use manual valve operation must have the capability to monitor pressures and gas flow rates on the pipeline to be able to identify and locate a rupture;

(4) Initiated to close as soon as practicable after identifying a rupture and with complete valve shut-off within 40 minutes of rupture identification as specified in paragraph (c)(1) of this section; and

(5) Monitored and controlled by remote personnel or must have a back-up power source to maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.

(g) *Monitoring of valve shut-off response status.* Operating control personnel must continually monitor rupture-mitigation valve position and operational status of all rupture-mitigation valves for the affected shut-off segment during and after a rupture event until the pipeline segment is isolated. Such monitoring must be maintained through continual electronic communications with remote instrumentation or through continual verbal communication with onsite personnel stationed at each rupture-mitigation valve, via telephone, radio, or equivalent means.

(h) *Alternative equivalent technology or manual valves for onshore rupture mitigation.* If an operator elects to use alternative equivalent technology or manual valves in accordance with § 195.258(c), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 195.452(m). The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology in lieu of a manual valve would be economically, technically, or operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valves 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valves or that PHMSA requires additional time to conduct its review.

16. In § 195.420, paragraph (b) is revised and paragraphs (d), (e), and (f) are added to read as follows:

§ 195.420 Valve maintenance.

* * * * *

(b) Each operator must, at intervals not exceeding 7½ months but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly. Each valve installed under § 195.258(c) or rupture-mitigation valve, as defined under § 195.418, must also be partially operated as part of the inspection.

* * * * *

(d) For each valve installed under § 195.258(c) or onshore rupture-mitigation valve identified under § 195.418 that is remote-control shut-off, automatic shut-off, or that is based on alternative equivalent technology, the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 195.446(c) and (e), or perform an equivalent verification.

(e) For each onshore rupture-mitigation valve identified under § 195.418 that is to be manually or locally operated:

(1) Operators must establish the 40-minute total response time as required by § 195.418 through an initial drill and through periodic validation as required by paragraph (e)(2) of this section. Each phase of the drill response must be reviewed and the results documented to validate the total response time, including valve shut-off, as being less than or equal to 40 minutes.

(2) A rupture-mitigation valve within each pipeline system and within each operating or maintenance field work unit must be randomly selected for an annual 40-minute total response time validation drill simulating worst-case conditions for that location to ensure compliance. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months.

(3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 195.418 no later than 6 months after the drill. Alternative valve shut-off measures must be in accordance with paragraph (f) of this section within 7 days of the drill.

(4) Based on the results of response-time drills, the operator must include lessons learned in:

(i) Training and qualifications programs; and

(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals.

(iii) Any other areas identified by the operator as needing improvement.

(f) Each operator must take remedial measures to correct any onshore valve installed under § 195.258(c) or rupture-mitigation valve identified under § 195.418 that is found inoperable or unable to maintain shut-off as follows:

(1) Repair or replace the valve as soon as practicable but no later than 6 months after the finding; and

(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made. Repairs must be completed within 6 months.

■ 17. In § 195.452, paragraph (i)(4) is revised to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(i) * * *

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

(i) Where EFRDs are installed to protect HCAs on all onshore pipelines with diameters of 6 inches or greater and that are placed into service or that have had 2 or more contiguous miles of pipe replaced after [insert date 12 months after effective date of this rule], the location, installation, actuation, operation, and maintenance of such EFRDs (including valve actuators, personnel response, operational control centers, SCADA, communications, and procedures) must meet the design, operation, testing, maintenance, and rupture mitigation requirements of §§ 195.258, 195.260, 195.402, 195.418, and 195.420.

(ii) The EFRD analysis and assessments specified in paragraph (i)(4) of this section must be completed prior to placing into service all onshore pipelines with diameters of 6 inches or greater and that are constructed or that have had 2 or more contiguous miles of pipe replaced after [insert date 12 months after effective date of this rule]. Implementation of EFRD findings for rupture-mitigation valves must meet § 195.418.

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